The Commonwealth of Massachusetts

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

November 30, 2005

D.T.E. 05-27

Investigation by the Department of Telecommunications and Energy on its own motion pursuant to General Laws c. 164, § 94, and 220 C.M.R. §§ 5.00 et seq. as to the propriety of the rates and charges set forth in the following tariffs: M.D.T.E. Nos. 34 through 68, filed with the Department on April 27, 2005 by Bay State Gas Company.

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I. INTRODUCTION

A. Procedural History

On April 27, 2005, Bay State Gas Company ("Bay State" or "Company") filed with the Department of Telecommunications and Energy ("Department"), pursuant to G.L. c. 164, § 94 and 220 C.M.R. §§ 5.00 et. seq., a petition seeking approval of proposed new tariffs, M.D.T.E. Nos. 34 through 68, attached to the petition, which are designed to increase its base distribution rates by $22.2 million for firm customers (Exh. BSG/SHB-1, at 4).[1] The Company uses a test year ending December 31, 2004 (Exh. BSG/JES-1, at 6-7). The Company's petition also includes a request for approval of tariffs establishing a performance-based regulation ("PBR") plan, under which the Company proposes to adjust its rates annually for five years (Exh. BSG/SHB-1, at 5).

Bay State provides retail natural gas service to approximately 285,000 customers in three non-contiguous divisions identified by their major cities (i.e., Springfield, Brockton and Lawrence). Bay State is a wholly-owned subsidiary of NiSource Inc. ("NiSource"), which is a registered public utility holding company located in Merrillville, Indiana. NiSource Corporate Services Company, Inc. ("NCSC") is a subsidiary of NiSource that centralizes and provides professional and managerial services to the NiSource operating companies, including Bay

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[1] In addition to the increase in rates, the Company proposes to collect through separate rate recovery mechanisms (1) pension and postretirement benefits other than pension expenses, and (2) steel infrastructure replacement costs (Exh. BSG/SHB-1, at 5).

State.[2] Also, Northern Utilities, Inc. ("Northern Utilities"), which provides natural gas distribution service in New Hampshire and Maine, and Bay State GPE, which is a special-purpose corporation created to hold Bay State's electric production facility in Agawam, Massachusetts, are corporate subsidiaries of Bay State. Bay State's last increase in base rates was approved by the Department on December 31, 1997. Bay State Gas Company, D.P.U. 97-97 (1997) (settlement); see also Bay State Gas Company, D.P.U. 92-111 (1992).

The Department docketed the petition as D.T.E. 05-27 and suspended all tariffs accompanying the petition for further investigation until December 1, 2005. Pursuant to notice duly issued, the Department held public hearings as follows: on May 25, 2005 in Ludlow; on May 26, 2005 in Brockton; and, on May 31, 2005 in Andover. On May 6, 2005, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G. L. c. 12, § 11E. Additionally, on May 24, 2005, the Hearing Officer granted intervenor status to the Associated Industries of Massachusetts ("AIM"); Local 273, Utility Workers Union of America, AFL-CIO ("Local 273" or "UWUA"); United Steelworkers of America AFL-CIO-CLC ("Steelworkers" or "USWA"); and limited participant status to Western Massachusetts Electric Company. On June 2, 2005, the Hearing Officer granted intervenor status to the Commonwealth of Massachusetts Division of Energy Resources ("DOER"); KeySpan Energy Delivery New England ("KeySpan"); Low-Income Weatherization and Fuel Assistance Program Network; Massachusetts Association for

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[2] NiSource and NCSC are each is subject to the jurisdiction of the Securities and Exchange Commission.

Community Action; Massachusetts Energy Directors Association; Massachusetts OilHeat Council, Inc. ("MOC"); MASSPOWER; NSTAR Gas Company, Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company (collectively "NSTAR"); and limited participant status to New England Gas Company, and Fitchburg Gas and Electric Light Company d/b/a Unitil. On June 14, 2005, the Hearing Officer granted limited participant status to The Berkshire Gas Company.

The Department held 26 days of evidentiary hearings between July 5, 2005 and August 11, 2005. The Attorney General, DOER, UWUA, USWA, MOC, and KeySpan filed initial briefs on August 31, 2005.[3] The Company filed its initial brief on September 14, 2005 ("Company Brief" or "Bay State Brief"). The Attorney General, Local 273, MOC, and AIM filed reply briefs on September 26, 2005, and the Company replied on September 30, 2005.[4]

The evidentiary record consists of over 1,900 exhibits, including all responses to discovery, as well as 301 responses to record requests. The Department granted the Company's motions for protective treatment of confidential material, which were unopposed and filed throughout this the proceeding.

In support of its filing, Bay State sponsored the testimony of nine (9) witnesses: Stephen H. Bryant, president of Bay State; Danny G. Cote, general manager of Bay State; John E. Skirtich, a consultant with Adecco Technical; Steven Barkauskas, vice-president of Total Rewards for NCSC; Joseph Ferro, manager of Bay State's regulatory policy; Earl

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[3] Initial briefs shall be referred to by entity name and the term "Brief."

[4] Reply briefs shall be referred to by entity name and the term "Reply Brief."

Robinson, a consultant with AUS Consultants; Paul Moul, managing consultant of P. Moul and Associates; Lawrence R. Kaufmann, partner at Pacific Economics Group, L.L.C.; and James Harrison, a consultant with Management Applications Consulting, Inc. Bay State also made available for questioning its call center manager, Patricia Teague.

The Attorney General sponsored four (4) witnesses: David Effron, utility regulation consultant with Berkshire Consulting Group; Jon R. Cavallo, a consulting engineer; Timothy Newhard, financial analyst in the Utilities Division of the Attorney General; and Jacob Pous, a depreciation expert with Diversified Utility Consultants. The UWUA sponsored four (4) witnesses: Nancy Brockway, of NBrockway and Associates; Kevin Friary, employee of Bay State and president of Local 273; Timothy Leary, employee of Bay State and vice president of Local 273; and Brian McCarthy, employee of Bay State. The Steelworkers presented the testimony of two (2) Bay State employees: Jody Ajar and Helen Vonmaluski. DOER presented the testimony of Alvaro Pereiro, Ph.D., manager of energy supply and pricing at DOER. KeySpan presented the testimony of Joseph Bodanza, senior vice-president of regulatory affairs and chief accounting officer for KeySpan.

Bay State sponsored rebuttal testimony through both individuals and panels. Mr. Bryant, Mr. Skirtich, and Mr. Moul responded as a panel to Mr. Effron's testimony, and Mr. Bryant and Mr. Cote responded as a panel regarding both Mr. Cavallo's replacement testimony and Ms. Brockway's testimony. Mr. Moul responded to Mr. Newhard's testimony, Mr. Robinson responded to Mr. Pous's testimony, and Mr. Kaufmann responded to Dr. Pereira's testimony.

B. Outstanding Motions

1. Motion to Bifurcate

On June 2, 2005, the Attorney General filed a Motion to Bifurcate the PBR, steel infrastructure replacement, and pension portions of this proceeding from the revenue requirement portion ("Motion to Bifurcate"). In support of the motion, the Attorney General stated that bifurcation would ease the administrative burden on the Department and all intervenors, and permit sufficient time for case preparation, presentation of evidence, and cross-examination (Motion to Bifurcate at 1). On June 10, 2005, the Company opposed the motion, responding that the PBR issue was not as complicated as the Attorney General asserted and that it could be addressed in the time allotted. The Attorney General responded on June 20, 2005.

The subject matters that the Attorney General seeks to bifurcate have been addressed during the course of this proceeding in the time period set by the procedural schedule and within the statutory deadline applicable to a case filing. See G.L.c. 25, § 18. The Attorney General's motion is moot. See, e.g., Boston Gas Company, D.T.E. 03-40, at 4 (2003).

2. Motion for Leave for Entry Upon Property and Inspection

On June 10, 2005, the Attorney General filed a Motion for Leave for Entry Upon Property and Inspections. During the course of this proceeding, the Company offered a site visit for viewing and a facilities tour. The Attorney General's motion is moot.

3. Motion to Compel Responses to Discovery

On June 16, 2005, the Attorney General filed a motion to compel responses to two information requests. The Attorney General's motion became moot when the Company provided those responses.

4. Conclusion

All matters that are subject of the outstanding motions are moot. The Department proceeded with evidentiary hearings and briefing of the issues presented in this case, including the PBR plan, steel replacement, and pension issues, and now decides those issues, as well as all of the revenue requirement issues in this Order. Therefore, the three outstanding motions are moot.

II. STEEL INFRASTRUCTURE REPLACEMENT PROGRAM

A. Description of the SIR Program

At the end of 2004, Bay State had a total of 477 miles of unprotected bare steel and 106 miles of unprotected coated steel mains for a total of 583 miles of unprotected steel mains (Exhs. BSG/DGC-1, at 16; AG 2-1, Att. at 4; RR-DTE-10).[5] This mileage represents 12 percent of Bay State's 2004 total of 4,718 miles of mains, which, in addition to unprotected

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[5] During the post-World War II construction boom, Bay State and its predecessors installed a significant amount of bare steel mains and services (Exh. BSG/DGC-1, at 11). To combat corrosion, local distribution companies ("LDCs"), including Bay State, then begun using various types of coated steel. Bay State laid its last non-cathodically protected coated steel mains and services in 1970 (id. at 12). Federal regulations (49 C.F.R. § 192.455) required that buried pipelines installed after July 31, 1971, must be cathodically protected against external corrosion. Thereafter, LDCs, including Bay State, began installing coated mains that were cathodically protected.

steel mains. includes cathodically-protected coated steel, plastic, cast iron and wrought iron pipe (Exh. AG-2-1, Att. at 4; RR-DTE-10, Att. at 4). The Company states that it had a system-wide average of approximately 700 corrosion leaks per year over the past five years, which it claims to be three times the corrosion leaks that occurred 17 years ago, despite its 700-mile reduction in inventory of unprotected steel mains (Exh. BSG/DGC-1, at 16).[6] The Company adds that its Brockton service area alone accounts for 63 percent of the Company's total of 583 miles of unprotected steel mains (id. at 16-17). The Company states that corrosion leaks in Brockton increased by 50 percent during a ten-year period from 404 leaks in 1993 to 601 leaks in 2003, even though Bay State retired or replaced 175 miles (31 percent) of its unprotected steel mains during that period (id.).[7]

In 2004, Bay State initiated a steel infrastructure replacement ("SIR") program that it claims will accelerate the replacement of the Company's unprotected steel mains, services and

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[6] Bay State's system-wide annual average corrosion leaks for the five-year period from 2000 to 2004 was 709.6 (RR-DTE-10, Att. at 4). Dividing this number by the 250 leaks in 1987 is equal to 2.8 (id.). However, if the annual leaks ten years ago of 693 (1994) were used as the divisor, the resulting ratio is 1.0 (id.). Bay State's system-wide annual corrosion leaks from 1985 through 2004 range from 250 in 1987 to 804 in 2000, with an average of 0.64 leaks per mile for the 1985-2004 period (id.). During the 1985-2004 period, Bay State replaced a total of 707 miles of unprotected steel, consisting of 159 miles of unprotected bare steel and 548 miles of unprotected coated steel (id.).

[7] If the ten-year period from 1994 to 2004 were used for comparison, the total number of corrosion leaks in the Brockton service area decreased from 561 leaks in 1994 to 509 leaks in 2004, a decrease of nine percent (Exh. AG 2-1, Att. at 4; Tr. 6, at 1070). During the same period, Bay State replaced 166 miles of steel mains (representing an average replacement rate of 16.6 miles per year), reducing the total unprotected mains for the Brockton service area from 534 miles to 368 miles (id.).

associated facilities that are subject to corrosion over a period of ten to 15 years (Exhs. BSG/SHB-1, at 36, 38; BSG/DGC-1, at 15, 23).[8] Bay State plans to invest approximately $20 million per year starting in 2005 ($8 million was committed in 2004), in addition to what it has normally spent on its steel infrastructure such that it will be spending a total of more than $25 million per year on steel infrastructure replacement (Exhs. BSG/SHB-1, at 36, 39-40, 44; BSG/DGC-1, at 22). The Company states that it arrived at the $20 million additional annual investment amount based on the length of annual footage for replacement and the ability of the Company to effectively manage the replacement of its steel infrastructure (Tr. 6, at 1077-1079).[9] The Company states that the total cost of the SIR program is estimated at $306 million in 2004 dollars (Exh. BSG/DGC-1, at 26). The Company notes that in planning the SIR program, it considered defined lengths of time but decided to replace those

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[8] Unprotected steel consist of: (1) bare steel pipe that has no exterior coating and has no cathodic protection installed on the pipe; and (2) coated steel pipe with no cathodic protection (Exh. BSG/DGC-1, at 11-12).

[9] One of the two studies performed by R.J. Rudden Associates, Inc. for Bay State dated March 10, 2005, entitled "Report to Bay State Gas Company Regarding Distribution Infrastructure Replacement," recommended that Bay State accelerate its current replacement schedule for steel infrastructure, suggesting a ten- to 15- year period of replacement at an annual cost over the 15-year period of $19.278 million (Exh. AG 2-16 (b) at 9). The Company agreed with the report's recommendation but indicated that it would have filed its SIR program without the studies, stating that its leak experience indicated the need for such a program (Exh. AG-2-16(b), at 9; Tr. 1, at 73-74; Tr. 6, at 1053-1054, 1075; Tr. 12, at 1965; RR-AG-20, Att. 20(a) at 1). The other study performed by R.J. Rudden Associates, Inc. dated February 18, 2005 and entitled "Comparison of Industry Corrosion Leak Data to Bay State Gas Company" was filed as Exhibit AG 2-16(a).

facilities in as short a time frame as possible of ten to 15 years, taking into account customer rate impacts and program implementation (Exh. BSG/DGC-1, at 26).

The Company claims that corrosion leakage on unprotected steel will not slow down, and the rate of leakage will accelerate as the unprotected steel facilities continue to deteriorate (id. at 18). Bay State also claims that such acceleration of the corrosion rate of unprotected steel is threatening to outstrip Bay State's ability to cost-effectively address the rate of leakage (id. at 17). The Company adds that the risk of injury and unsafe conditions continues to escalate, and that system degradation due to corrosion will challenge Bay State's ability to meet peak day needs and operate the system safely (id. at 20).[10] Bay State claims that, based on its average replacement rate over the last five years, it would take approximately 30 to 40 years to replace its remaining unprotected steel and it would not be prudent to extend its replacement period for that length of time (id. at 17).

The Company claims that the most cost effective method of replacement is to undertake an area-based, or geographic, replacement strategy that will permit the Company to bid the work to contractors competitively, and a contractor to price its bid based on an efficient program implemented by geographic region (id. at 18-19). The Company adds that by targeting discrete areas, neighborhood-by-neighborhood, block-by-block in a geographically contiguous area, construction crews can stage work continuously by shifting the worksite along

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[10] Bay State claims that its record for system operation is very strong and meets or exceeds state and federal requirements for leak surveying, and that since 1993, the Company was ranked in the first quartile (21 percent) of companies experiencing the fewest number of leaks in backlog at year-end based on a ranking of regional local distribution companies (Exh. BSG/DGC-1, at 9).

the pipe rather than, what is often the case under the current method of replacement and repair, where crews open and close worksites and relocate labor and equipment across town or across the service territory (id. at 19). The Company claims that it has consistently seen lower costs per job if it bundles work together in the same geographic area (id.; DTE-3-28).

The Company, however, indicates that under its SIR program, it does not have a long-term list of targeted locations to be accomplished, prioritized by date from the date of SIR program implementation through 2014 or later (Exh. DTE 3-29). The Company claims that guidance in a construction activity is provided on a locational or municipal basis on a six-, twelve-, or 18-month-ahead notice and not out 15 years (id.). The Company adds that to establish its plan for geographic replacement of unprotected steel, following each year as part of its construction season planning process, it considers: (1) areas with high corrosion leakage; (2) areas where there is planned municipal work; and (3) any emergency situations (id. at 2).

B. Proposed Ratemaking Treatment of SIR Program Incremental Costs

The Company proposes to recover the costs of its annual incremental investment under its SIR program through a SIR base rate adjustment mechanism (Exhs. BSG/SHB-1, at 39; BSG/JAF-3-1, M.D.T.E. No. 63, §§ 2.2, 5.0, 6.0). In determining the annual incremental investments for cost recovery, the Company proposes to reduce the total amount of all unprotected steel replacement facilities installed in a given year for all completed projects by a four-year average "historic" level of steel replacement (Exhs. BSG/JES-1, at 67; DTE 3-33). The Company proposes that the average direct expenditures for steel replacement during the

2000-2003 period of $4,041,244 be used to represent the "historic" level of steel replacement (Exh. BSG/JES-1, Sch. JES-17, at 3 (Rev.)).[11] Bay State states that this method is used because it cannot readily identify, from an operational and accounting perspective, the incremental portion of the unprotected steel replacement expenditures (Exhs. BSG/JES-1, at 67; DTE 3-33).

The SIR base rate adjustment mechanism specifies the formula to be used to adjust, on an annual basis effective November 1, 2006, each rate element of customer, volumetric, or demand charge of each class's base distribution rates (Exh. BSG/JAF-3-1, M.D.T.E. No. 63, at 1).[12] The SIR revenue requirement, to be used as the basis for determining the annual base rate adjustment, includes all incremental SIR direct program costs that consist of the following expenses: depreciation, property taxes, carrying costs, income taxes, and return on investment, with offset for possible reduction in operating and maintenance leak repair costs ("O&M Offset") as a result of reduction in main corrosion leak repair activities

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[11] Bay State states that the reason why its historic level of replacement only includes 2000 through 2003 capital expenditures is because replacement was accelerated in 2004 and, therefore, did not represent what typically occurred in the past (Exh. DTE 3-33). The annual direct expenditures for the replacement of unprotected steel mains, services and other related facilities from 2000 through 2004 are $2.6 million, $5.2 million, $3.8 million, $4.6 million, and $6.2 million, respectively (id.).

[12] The SIR base rate adjustment mechanism is a component of the Company's proposed Annual Base Rate Adjustment Mechanism tariff, M.D.T.E. No. 63. This tariff specifies the procedure to adjust, on an annual basis effective November 1, 2006, the Company's base distribution rates for firm gas sales and firm transportation service pursuant to the Company's PBR price cap mechanism and its SIR program, and including the annualized impact of the energy savings savings from the Company's demand-side management program (Exh. BSG/JAF-3-1, M.D.T.E. No. 63, at 1).

(Exh. BSG/JES-1, at 67-69, Sch. 17). The carrying cost component of the SIR revenue requirement is calculated as the interest cost of the Company's capital investments, incurred from the time the plant is placed in service to the time when the base distribution rates have been adjusted, using the Company's pre-tax weighted average cost of capital approved in the instant docket (Exh. BSG/JES-1, Sch. 17, at 9).[13] The return on investment is calculated as the product of the Company's SIR eligible facilities additions plus overhead and net of depreciation and taxes, and the Company's pre-tax weighted average cost of capital approved in the instant docket (id. at 1). The SIR eligible facilities addition is equal to the total current year direct investment less the Company's historic 2000-2003 average unprotected steel infrastructure investment described above (id. at 2). The O&M Offset is determined by comparing the expense for leak repair activity of the previous year's SIR program year to the four-year average expense of leak repair activity for the period 2000 through 2003 (Exh. BSG/JES-1, at 69, Sch. JES-17, at 12).

The Company states that its filing for the annual SIR base rate adjustment would include a summary of proposed SIR revenues, plant-in-service that was added through the SIR program, plant-in-service retired or removed, calculations for depreciation expense, accumulated depreciation, carrying charges, property tax offsets, the allowed return on investments, and the allocation of the increase in revenue requirement among rate classes with

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[13] The Company's proposed pre-tax weighted average cost of capital is equal to 13.05 percent (Exhs. BSG/JES-1, Sch. 17, at 1, 10; BSG/PRM-2, Sch. PRM-1). Alternatively, the Company states that it would be feasible to use the incremental cost of capital in calculating the carrying costs instead of the pre-tax weighted average cost of capital (RR-DTE-39; Exh. DTE 18-26).

the corresponding bill impact analysis by rate class (Exh. BSG/SHB-1, at 42). In addition, the annual filing would include a construction audit package describing in detail the past year's activity and the SIR construction forecast (id.). The Company states that this part of the filing is intended to provide the Department all the necessary materials to be able to conduct a complete audit of the program investments (id.). These materials would include: (1) a summary of annual program budget by job type; (2) a summary of actual expenditures by job; (3) a summary of corrosion leaks and total leaks per mile each year between 2000-2004, as well as for each year subsequent to the SIR program implementation; (4) a summary of steel footage replaced by type, along with a rolling estimate of the remaining footage to be replaced; (5) a detailed description of the cost of management procedures used, including competitive bidding, on-site supervision, and cost-overrun authorization monitoring and control; (6) copies of project authorization forms, including all necessary approvals; (7) work order management system backup job; (8) copies of all invoices over $1,000; and (9) a complete variance analysis for total project costs (id. at 42-43).[14]

The Company concludes that its proposed SIR base rate adjustment mechanism will allow Bay State to recover the costs of its incremental investment under the SIR program, will

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[14] Given the number of invoices associated with its initially-proposed annual SIR program filing package, Bay State, instead, proposes "to include a representative sample of all project invoices acceptable to the Department for its review of the annual SIR Program (e.g. [three] projects under $25,000, [three] projects between $25,001 - $50,000, and [three] projects greater than $50,000). The Company can further address this issue with the Department following its issuance of a final order in D.T.E. 05-27" (Exh. DTE 3-34, Supp. at 2). The Company, however, added that it will be prepared to provide all records of all capital investments that the Department would require (Tr. 24, at 4017).

be updated annually after the close of the construction season, and will allow the Department, the Attorney General and other parties to review annually Bay State's SIR program (id. at 39).[15]

C. Positions of the Parties

1. Attorney General

The Attorney General urges the Department to reject the Company's proposed SIR program cost recovery mechanism because: (1) the Company deferred unprotected steel main replacements during the five-year rate freeze ordered by the Department in NIPSCo/Bay State Acquisition, D.T.E. 98-31 (1998) ("merger");[16] (2) the geographic approach does not prioritize replacement based on safety and is not the least cost approach to steel infrastructure replacement; (3) the SIR program is technically flawed; and (4) the SIR program base rate adjustment, in addition to and separate from a PBR base rate adjustment, is not consistent with the Department's precedent on incentive regulation in that the payments for the accelerated replacement of the Company's steel infrastructure are unnecessary and duplicative (Attorney General Brief at 16-28; Attorney General Reply Brief at 3-14). Each of these items is discussed below.

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[15] The Company also describes programs similar to the proposed SIR program recovery mechanism implemented in other jurisdictions (Exh. AG 2-59; RR-DTE-5, RR-DTE-52; RR-DTE-62).

[16] In 1998, the Department approved the acquisition of Bay State by NIPSCO Industries, Inc., including a rate plan with a five-year rate freeze. NIPSCo/Bay State Acquisition, D.T.E. 98-31 (1998). In 1999, NIPSCO Industries, Inc. was renamed NiSource Inc.

Regarding the alleged deferral of unprotected steel main replacement, the Attorney General claims that during the merger five-year rate freeze the Company deferred needed pipe maintenance in general and, in particular, the replacement of bare steel pipe in the Brockton division (Attorney General Brief at 17-18; Attorney General Reply Brief at 5-6). To support his claim, the Attorney General states that: (1) bare steel main abandonment for the Brockton division declined from 67,432 feet in 1998 to 21,473 feet in 2002, or a 68 percent reduction (Attorney General Brief at 17-18, citing Exh. AG 2-39, at 1); (2) Company-wide bare steel abandonment declined from 89,695 feet in 1998 to 32,162 feet in 2002, or 64 percent reduction (id. at 18-19, citing Exhs. AG 2-38; AG-9, at 7, line 2); (3) Company-wide installation of new and replacement mains declined from 425,706 feet in 1998 to 172,237 feet in 2002 (id. at 19, citing Exh. UWUA 1-27); and (4) the Company reduced its unprotected steel mains at an average rate of 46 miles per year during the period between 1985 and 1997, but after the merger the average rate went down to 15 miles per year between 1998 and 2003 (id. at 20, citing Exh. UWUA-4, at 24-27).[17]

The Attorney General also claims that following the merger, the Company ordered its field crews to repair rather than replace unprotected steel mains, contrary to the United States Department of Transportation guidance regarding pipeline repair and the Company's own Operations and Maintenance Manual (id. at 20-21, citing Exhs. BSG-AG 2-22; BSG-AG 2-25;

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[17] In addition, the Attorney General claims that: (1) capital investments fell over 50 percent in years immediately following the merger (Attorney General Brief at 20, citing Exh. UWUA-4, at 24-27); and (2) the Company reduced its main repair and replacement supervisors by 50 percent in the Brockton division during the period from 1998 to 2003 (id. at 20, citing Exh. UWUA 1-19(a); Tr. 2, at 309).

AG 6-1, Procedure, 14, 15, § 9; Attorney General Reply Brief at 6). The Attorney General notes that the Company was experiencing an increasing leak rate and corrosion leaks from 1998 to 2000 in the Brockton division as well as on a Company-wide basis (Attorney General Brief at 21, citing Exh. AG 2-1, at 1, 4, columns M, O). The Attorney General claims that industry studies have shown that when a section of a pipeline system starts to develop leaks, further leaks will develop at a continuously increasing rate (id. at 21, citing Exh. AG 2-16(b)).

The Attorney General contends that the Company is using the consequences of its decision, i.e., to defer unprotected steel main replacement in the Brockton division, as a justification for the accelerated replacement (Attorney General Brief at 21). The Attorney General asserts that customers are entitled to the whole benefit of the entire five years of fixed distribution rates under the merger rate freeze and not merely deferral of rate increases (id. at 21-22, citing NIPSCo/Bay State Acquisition, D.T.E. 98-31, at 17 (1998)).[18] Accordingly, the Attorney General recommends that Bay State not be allowed to benefit from its attempt to avoid the consequences of the merger rate freeze by deferring the costs of an important element

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[18] UWUA claims that test year expenses are not representative but artificially inflated, noting that the average annual capital expenditure from 1996 to 1999 was $46.9 million, that from 2000-2003 it was $30.5 million, and the 2004 capital expenditure increased by one-third from the 2003 level (UWUA Brief at 13). UWUA states that the Department should be concerned about Bay State sharply cutting expenditures and staff when it is under a rate freeze and then ramping up expenditures and staffing just before it files a rate case, especially in light of its proposal for PBR and SIR adjustment mechanisms (id. at 14-15).

of its service obligation, and thereafter requesting cost recovery under the guise of the accelerated steel replacement program (id. at 21).[19]

Regarding Bay State's geographic approach for unprotected steel main replacement that starts with the Brockton division, the Attorney General suggests that the Department reject this approach and direct the Company to replace its steel infrastructure based on a schedule that allows the replacement of pipe segments that pose the greatest risk to public safety (id. at 22-23). The Attorney General contends that the Company has not demonstrated that all of its unprotected steel mains and services require replacement on an expedited basis (Attorney General Reply Brief at 4).[20] The Attorney General notes that there are substantial variations in rates of corrosion among the towns within the Brockton service area and, on that basis, the Company could target the higher segments first with accelerated replacement and need not replace its entire unprotected steel distribution system (id. at 4 citing Exh. AG 14-19(c)). The Attorney General claims that by using the "safety first" approach, the Company would be able to rapidly address any problem areas across the entire Company's service areas, rather than just the Brockton division, and therefore, more quickly reduce the Company's rate of corrosion

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[19] The Attorney General suggests that, since the Company has put the public at risk by neglecting its infrastructure in the Brockton service area, the Company should implement the "safety first" approach to replace the worsening pipes on an expedited basis at the Company's expense to make up for years of lagging bare steel replacements during the merger rate freeze (Attorney General Reply Brief at 4, n.4).

[20] The Attorney General notes that although the Company indicated that corrosion leaks would go beyond its control based on a rate of 1.54 leaks per mile in 2003, it had no apprehension of such a crisis in 2000 with a corrosion leak rate of 1.53 per mile during the middle of the merger rate freeze (Attorney General Brief at 20, citing Exh. AG 2-1, at 1; Tr. 2, at 306).

leaks (Attorney General Brief at 22-23). The Attorney General's corrosion expert, Mr. Cavallo, endorses this "safety first" approach as sound corrosion mitigation engineering, and criticizes the Company's geographic approach to prioritizing replacements as leaving high-risk pipe segments in the ground that threaten public safety (id. at 24, citing Tr. 17, at 2771-2773).

The Attorney General asserts that the Company will not realize savings with its geographic approach (Attorney General Brief at 24). The Attorney General argues that because the geographic approach does not target the worst segments of pipes first, it requires the costly replacement of the entire unprotected steel infrastructure on an accelerated schedule in all of the Company's service areas (Attorney General Reply Brief at 5). The Attorney General disputes the Company's claim that the geographic approach, which would replace longer segments of pipes, would result in cheaper bid prices of up to 20 percent per foot of installation for segments over 1000 feet, compared to the costs of segments of pipe 300 feet or less (Attorney General Brief at 24, citing Exh. DTE 3-28; RR-AG-87). The Attorney General argues that for such comparison to be valid, it presumes that the most risky segments of pipes to be replaced are in fact all small and widely dispersed (id., citing Exh. DTE 3-28; RR-AG-87). The Attorney General claims that the Company has not produced any study that supports such a presumption (id., citing Exh. DTE 3-28; RR-AG-87). The Attorney General claims that the Company will not realize net savings in the long run, because it would still need to replace shorter and more costly segments regardless of where they are located in its distribution system (Attorney General Brief at 24).

The Attorney General also contends that the geographic approach would minimize the proposed SIR program O&M Offset because: (1) it does not necessarily replace the worst performing mains first and therefore will require additional repairs; and (2) leaky mains will put upward pressure on the Company's leaks per mile and help ensure that the Department does not terminate the recovery for accelerated SIR program costs before 100 percent of the mains are replaced, unlike the case of Northern Utilities where the New Hampshire Public Utilities Commission ("NHPUC") terminated payments for accelerated mains replacement after half of the mains were replaced (id. at 25-26, citing Exh. DTE-AG 2-5).

The Attorney General claims that the Company departed from the method ordered by the NHPUC for its affiliate Northern Utilities that first replaced the segments of pipe that posed the greatest risk, and then moved onto the less risky segments (id. at 23, citing Northern Utilities, DR 91-081, at 1 (1992)). The Attorney General claims that such a "safety first" approach was so successful that the NHPUC terminated payments under Northern Utilities' accelerated main replacement program after replacement of less than 50 percent of bare steel mains, because the program achieved a 0.6 leak per mile on a system-wide basis in 2000 (Attorney General Brief at 23; Attorney General Reply Brief at 4, citing DR 91-081, at 1 (1992); Northern Utilities, DG 99-127 / DG 00-177, at 2, 5 (2000)).[21]

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[21] In addition to the "safety first" approach, the Attorney General also referred to a probabilistic approach, which he claims to have been successfully used by the Army Corps of Engineers (Attorney General Reply Brief at 4, citing RR-DTE-117, Atts. 8, 9, 10).

Regarding the technical aspects of the SIR program, the Attorney General contends that the Company's SIR program suffers from a number of technical problems (Attorney General Brief at 26-28). First, the Company did not conduct a root cause analysis to determine the reasons for its leak rates, noting that the Department has found in the past that the root cause approach is useful for identifying a solution for infrastructure problems (id. at 26, citing Exhs. AG-7, at 7-9; AG 14-14; Report of the Department of Telecommunications and Energy relative to reducing the number of double utility poles within the Commonwealth, pursuant to Chapter 46 of the Acts of 2003, Section 110, D.T.E. 03-87, at 15 (2003)). The Attorney General claims that a root cause analysis could guide the Company as it prioritizes its steel infrastructure replacement, noting that different pipe materials can have different leak rates (Attorney General Brief at 26, citing Exhs. AG 2-1 (August 25, 2005); AG-7, at 14).[22]

Second, the Attorney General claims that the R.J. Rudden studies used by the Company as a basis for its SIR program have flaws, which render the results unreliable (id. at 28). The Attorney General notes that when comparing the Company's corrosion data to other gas utility companies' data, the study only focused on the performance of the Brockton division instead of the Company's overall performance (id. at 27, citing Exhs. AG 2-1 (June 6, 2005); AG 2-16(a), at 1; AG-14-19 (c) (Supp.)). The Attorney General also notes that the study did not select the comparison group of companies to reflect the same or comparable ratio of bare

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[22] The Attorney General, for example, notes that for 2004 the unprotected coated steel main in the Lawrence service area had a leak rate of 3.67 leaks per mile, while the leak rate for bare steel in the Brockton service area was 1.40 leaks per mile (Attorney General Brief at 26, citing Exh. AG 2-1 (August 25, 2005)).

steel mains and unprotected coated steel mains as that of the Brockton division, adding that several companies in the comparison group had no unprotected coated steel mains (id. at 27, citing Exh. AG 14-19(c) (Supp.); Tr. 15, at 2414). In addition, the Attorney General claims that at the initial meeting with R.J. Rudden, the Company provided a predetermined $20 million annual spending level under the SIR program, and the R.J. Rudden report eventually recommended spending in that range (id. at 27-28, citing Exh. AG 14-19(a), at 1; Tr. 2, at 441-444).

Third, the Attorney General claims that the R.J. Rudden study uses an understated average historic replacement rate, which predicts 30 to 40 years to achieve full replacement of unprotected steel mains, to help convince the Department that the Company lacks the ability to replace its steel infrastructure at an appropriate rate without extra payments from customers (Attorney General Reply Brief at 6-7). More specifically, the Attorney General asserts that the Company's definition of its "historic" rate of replacement, as the average over the last five years,[23] is unreliable and understated because it covers the merger rate freeze period during which the Company deferred unprotected steel main replacement and cut its staff (id., citing Company Brief at 27; Exh. AG 2-16(b), at 6)). The Attorney General suggests that when calculating the "historic" replacement rate, R.J. Rudden Associates ("R.J. Rudden") should have used a ten-year period from 1992 through 1999 and 2003 through 2004, excluding the

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[23] The Company's filing indicates "SIR Base Rate Adjustment, Historical Bare Steel Replacement Capital Expenditures, Direct Costs, 2000 through 2003" and provides an average replacement rate over the 2000 through 2003 four-year period (Exh. BSG/JES-17, Sch. JES-17, at 3).

2000 through 2002 main replacement data, to correct for the Company's deferrals of unprotected steel main replacement (id. at 7).[24]

The Attorney General also claims that a separate SIR base rate adjustment concurrent with a PBR mechanism is not consistent with the Department's precedent on incentive regulation (id. at 8, citing Incentive Regulation, D.P.U. 94-158 (1995); D.P.U. 96-50 (1996); Boston Gas Company v. Department of Telecommunications and Energy, 436 Mass. 233, 234 (2002)). The Attorney General states that the Company offered no legal basis for proposing a base rate increase under G.L. c. 164, § 94, to establish cast-off rates separating out the SIR program while at the same time requesting an automatic increase in rates under a G.L. c. 164, § 1E, PBR plan (id. at 8-9). The Attorney General observes that unlike the pension mechanism approved in NSTAR, D.T.E. 03-47 (2003), the SIR base rate adjustment mechanism is not a reconciling tariff and that the adjustment represents a substantial portion of

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[24] The Attorney General notes that the Company uses different calculations of its historic replacement rate (Attorney General Reply Brief at 7, n.5, citing Exh. BSG/DGC-1, at 17). First, because the Company indicated that it removed 700 miles of steel mains over a 19-year period, the Attorney General states that this represents an average replacement rate of 36.8 miles per year (id.). Second, noting that the 2004 remaining unprotected steel mains is 583 miles and that the Company indicated that based on the "historic" replacement over the last five years it will take 30-40 years to achieve full replacement, the Attorney General states that this means an average replacement rate of 19.4 miles per year (=583 miles/30 years) (Attorney General Reply Brief at 7, n.5). Finally, the Attorney General notes that for the purpose of determining the "incremental" expenditures under the SIR program cost recovery, the Company uses as its base cost period the four-year average of historical unprotected steel infrastructure replacement costs for 2000 to 2003, which the Attorney General claims to be low points during the years the Company deferred unprotected steel main replacement under the merger rate freeze (id., citing RR-DTE-145; Exhs.AG 2-39, at 1; AG-2-38; UWUA 1-27).

the expected Company cost increases in the future (id. at 9). The Attorney General claims that taking together the proposed annual SIR program base rate adjustment, the pension adjustment mechanism, the cost of gas adjustment, and the annual PBR increases, such a combination of adjustments would constitute a radical departure from the Department's established test year approach to setting just and reasonable rates (id. at 9). The Attorney General concludes that the SIR base rate adjustment is "antithetical to both traditional cost of service regulation and incentive plans, and the Department should reject it" (id. at 9).

Regarding the proposed annual SIR base rate adjustment as a separate component from the proposed annual PBR base rate adjustment, the Attorney General contends that this undermines the purpose of the price cap formula and PBR because it provides the Company no incentive to minimize capital costs or seek tradeoffs for other alternatives to the capital additions (Attorney General Brief at 35; Attorney General Reply Brief at 13-14). The Attorney General contends that instead, the Company will have the incentive to expand, assign, and allocate costs, whether direct or indirect, to the SIR eligible additions, thereby losing the fundamental balance of incentives in the price cap mechanism (Attorney General Reply Brief at 14).

Also, noting that Mr. Kaufman's productivity analysis is based on total costs, the Attorney General argues that removing a portion of the total cost of providing distribution service that relates to the SIR program destroys the relationship between inflation and productivity factors that are based on total costs (Attorney General Brief at 37; Attorney General Reply Brief at 13, citing Tr. 4, 705-708). The Attorney General contends that this is a

fatal flaw because using the proposed inflation index and productivity factor incorrectly increases rates (Attorney General Brief at 37). The Attorney General asserts that for this reason alone, the Department must reject the Company's proposal to extract capital costs out of the price cap formula in terms of a new capital additions recovery mechanism under the SIR program (id.).

The Attorney General asserts that the payments for the accelerated main replacement under the SIR are unnecessary or duplicative because the Company's proposed PBR mechanism: (1) automatically increases the cast-off rates each year to a level sufficient to cover costs expected from plant replacement; (2) has an earnings sharing mechanism that protects the Company in case a prudent plant replacement causes a severe earnings shortfall; and (3) has annual adjustments that are simple to calculate, unlike the SIR that would (I) represent a mini-rate case, (ii) would make it difficult for the Department to set the appropriate return, and (iii) would make refunds for double collection cumbersome because the SIR is not reconciling (Attorney General Reply Brief at 7-8).

The Attorney General rejects the Company's claim that its proposal will prevent double recovery of steel replacement costs, arguing that the Company's price cap formula includes test year end capital costs that are associated with the SIR eligible additions (id. at 14). The Attorney General asserts that double cost recovery can only be eliminated with the removal of all the test year capital costs embedded in base rates that are associated with the plant items for accelerated replacement under the SIR program (id.). The Attorney General contends that because the Company's proposed price cap formula removes from the price cap only the costs

associated with the incremental mains, services, and meter investments made after the test year, the Company will recover twice the replacement costs - once through the price cap increase and a second time through the SIR base rate adjustment mechanism (id.).

In addition, the Attorney General contends that approval of the annual SIR program base rate adjustment mechanism will require additional Department oversight and will prompt all other utilities under Department jurisdiction to seek similar mechanisms resulting in every utility having an annual "mini" rate case (Attorney General Brief at 36-37). The Attorney General considers this type of administrative oversight not only burdensome but an unworkable method of review for all gas, electric, and water companies under the Department's authority (id. at 36-37).[25]

2. DOER

DOER claims that the PBR mechanism in conjunction with a separate SIR base rate adjustment mechanism not only undermines all the benefits of the PBR approach but also distorts traditional cost of service regulation (DOER Brief at 8-9). DOER asserts that the Company's proposal to treat SIR program costs differently from other costs does not make sense and is not supported by the record (id.). DOER states that it is a well-established Department precedent to look at the total cost of a utility before allowing a rate increase

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[25] The Attorney General rejects the Company's claim that the SIR focuses on public safety objectives that are complementary to, but distinct from, the efficiency gains promoted by the PBR, arguing that such an approach does not identify which capital additions are safety related, and that the Company could conceivably argue that all of its plant assets are needed for safety and reliability (Attorney General Reply Brief at 13, citing Company Brief at 187-188).

because some costs could rise, other costs may fall, and revenues could increase to offset a portion of cost increases (id. at 8).

Regarding the Company's assertion that the PBR price cap formula will not accommodate the rapidly increasing expenditures under the SIR program, DOER claims that the Company has not shown that the SIR program costs are different from other capital costs (DOER Reply Brief at 4, citing Company Brief at 171). In addition, DOER asserts that the SIR program incremental costs proposed to be recovered are not exogenous costs, noting that the Department defined exogenous costs as those costs that a company cannot anticipate prior to entering into a long-term PBR plan (id., citing D.T.E. 03-40, at 490). DOER argues that because those costs do not fit the Department's definition of exogenous costs allowed for recovery under the PBR mechanism, the Company has sought an alternative that would circumvent the Department's policy on the recovery of exogenous costs (DOER Reply Brief at 4). DOER also contends that there will be no reduction in rate case expenses because of the annual filings, audits and review (DOER Brief at 9).

3. AIM

AIM states that the selective exclusion of the SIR related costs from the PBR plan eliminates the incentives for cost containment and efficiencies that provide ratepayers benefits (AIM Comments at 1). AIM states that, although it supports the necessary replacement of the Company's steel infrastructure, the Department should carefully review the Company's proposal that excludes SIR related costs from the PBR plan in order to develop appropriate incentives that maximize efficiencies to ensure ratepayer benefits (id.).

4. Bay State

The Company claims that its proposed SIR program cost recovery is appropriate because the magnitude of the SIR program is substantial both in cost and scope (Exh. BSG/SHB-38). The Company states that making repeated rate case filings to recover the incremental costs associated with the SIR program will be administratively inefficient and will drive up the costs ultimately borne by ratepayers (id.). The Company states that even if the Department were to grant its requested base rate increase, the amount would be insufficient to provide Bay State the opportunity to earn its allowed return during the five-year term of its proposed PBR price cap mechanism (Exh. BSG/SHB-39). Bay State adds that its proposed SIR program cost recovery is a fair and reasonable approach toward keeping the Company whole while under a PBR program or in between rate cases (Exh. DTE-3-33). The Company claims that it will have a significant short-fall in earnings in each year of the SIR program because of the substantial annual investments that are non-revenue producing, and that the PBR price cap mechanism does not contain any provision for recovering the costs associated with those investments (Exh. BSG/SHB-1, at 40).

Bay State claims that the Department approved a step adjustment in base rates for plant additions in Bay State's settled rate proceeding, D.P.U. 97-97, but it rejected a similar request in D.P.U. 92-111, because Bay State did not have a firm commitment to replace post-1860 vintage cast iron pipe at a specific rate of replacement (id. at 43). Bay State adds that the NHPUC approved for Bay State's affiliate, Northern Utilities, an annual base rate adjustment from 1992 through 1999 to recover depreciation and return on non-revenue producing plant

investments related to bare steel, less net revenues from new customers added along the route (id. at 44-45, citing Northern Utilities Inc., DR 91-081 (1992)).[26]

Bay State claims that the record evidence does not support the Attorney General's claim that the Company deferred the maintenance on its distribution system following the merger (Bay State Brief at 34; Bay State Reply Brief at 9). The Company asserts that it has been fully compliant with mandates for mains replacement established under 49 C.F.R. § 192.00 et seq. and the Department's cast iron replacement regulations under 220 C.M.R. §§ 113.00 et seq. (Bay State Brief at 34, citing Exhs. BSG/LRK-2, at 8; AG 6-10; USWA 2-20). The Company claims that the Department has regularly inspected Bay State's maintenance program and that the Department has never expressed any concern that Bay State was not fulfilling its operational and regulatory obligations, adding that it has been proactive in identifying problems associated with its unprotected steel infrastructure (Bay State Brief at 34, citing Exhs. AG 2-7; AG 2-8; AG 8-4; DTE 20-2; UWUA 3- 46).

Bay State notes that an important measure for evaluating the maintenance of distribution and interstate gas pipelines used by the Department and the federal Department of Transportation is whether leaks are identified and repaired within a reasonable time period

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[26] The Company indicated that unlike the geographic approach for its SIR program, the basis of Northern Utilities for prioritizing the bare steel infrastructure of its New Hampshire division was to replace the worst bare steel segments each year over a ten-year period (Exh. AG 2-59). In addition, unlike the SIR program, which is intended to replace 100 percent of Bay State's unprotected steel infrastructure over a ten-15-year period, Northern Utilities' program was not intended to replace 100 percent of its bare steel infrastructure and that after the end of ten years, bare steel would remain a component material in Northern Utilities' distribution system infrastructure (Exh. AG 2-59).

(Bay State Brief at 35, citing Exhs. AG 25-3; AG 2-33; DTE 3-12; RR-DTE-67; RR-DTE-71). Bay State claims that the record shows that it has immediately repaired the most dangerous type of gas leaks (Type 1) and that no party has challenged such evidence (id., citing Exhs. AG 25-5; AG 14-7; Bay State Reply Brief at 10, n.6, at 11). Bay State claims that it consistently repaired Type 2 leaks by year end, and that Bay State is in the top 20 percent of all gas companies in repairing Type 2 leaks (Bay State Brief at 35, citing Exhs. AG 25-5; AG 14-8; AG 2-16; AG 14-19; Bay State Reply Brief at 10, citing Exh. AG 2-16(a) at 3; Tr. at 359).[27] In addition, Bay State claims that it exceeds the requirements of federal and state codes in leak surveillance, noting that there is no evidence to show that the SIR program was necessitated by a failure to maintain the system (Bay State Brief at 35, citing Exhs. AG 14-19; AG 25-5; AG 14-18; Bay State Reply Brief at 10-11).

The Company states that it has the obligation to extend the life of its plant as far as possible into the future, taking into account the economics of repair versus replacement as well as safety concerns, because premature retirement of an aging but otherwise safe main could impose unnecessary costs (Bay State Brief at 36). The Company claims that it continually evaluates its leak trends and that it repairs or replaces affected mains as each individual circumstance requires (id.). Bay State, however, observes that its experience during the cold winter of 2002-2003 demonstrated that the Company's ability to manage its leak rate through

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[27] Bay State notes that the Department regularly looks at whether its jurisdictional companies are repairing Type 2 leaks by year end and what percentage remains to be repaired at year end (Bay State Brief at 35, citing Exhs. AG 14-19; AG 25-5; DTE 3-9).

repair was being outstripped by the number of leaks in the Brockton system (id.). The Company states that this experience served as the turning point in its decision making process, when the balance tipped from repair to replacement of mains (id.).

The Company claims that the Attorney General demonstrated no pattern of a failure to spend on pipe replacement, noting that the Company's replacement by miles, which is a better measure, is consistent from 1998 through 2002 when compared to the period 1986 through 2003 (Bay State Reply Brief at 10, citing Exh. AG 14-1). The Company asserts that the Attorney General's comparison of pre- and post-merger replacement rates by looking at levels of pipe abandonments is faulty because it is derived by selecting an historically high year as the starting point and an historically low year for an end point (id. at 10, citing Exhs. AG 14-1; AG 2-39). Contrary to the Attorney General's claim, Bay State asserts that it did not delay the replacement of mains in order to obtain recovery of costs under the SIR base rate adjustment (Bay State Brief at 36). The Company cites its repair rates as well as the number of miles of bare steel and unprotected steel that have been replaced as evidence to support its assertion disputing the Attorney General's claim (id.; Bay State Reply Brief at 11).[28]

Regarding the Attorney General's allegation that the Company instructs its field crews to repair leaks by clamping rather than replacing mains, the Company claims that this is considered good utility practice in order to eliminate the public safety risk of a leaking natural

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[28] Bay State notes that since 1995, it has replaced 130 miles of bare steel and 213 miles of coated unprotected steel in addition to those replaced between 1971 and 1995, in response to meeting the requirements of 49 C.F.R. §§ 192.00 (Bay State Brief at 36-37, citing Exhs. AG 14-1; AG 14-25; RR-AG-95).

gas main (Bay State Brief at 37). The Company states that following a repair, the field crews and their supervisors make recommendations as to whether the pipe should be replaced (id.). The Company adds that if the recommendation to replace the pipe is approved, then a contractor crew is assigned the replacement because that would be more cost effective (id.). The Company asserts that there is nothing irregular in this process (id.).

Regarding the geographic approach for the SIR program, the Company claims that although its current method of repairing or replacing pipes segment by segment works for certain mains such as cast iron replacement, the method is not appropriate to address the accelerating leaks confronting Bay State on its unprotected steel infrastructure (id. at 38; Bay State Reply Brief at 9). The Company claims that a geographic replacement approach: (1) costs less; (2) uses resources more efficiently with competitive bidding of labor and materials; and (3) causes less inconvenience to the public (Bay State Brief at 39; Bay State Reply Brief at 9).

The Company asserts that the systematic geographic replacement is undertaken now and will be continued in order to protect the public from the risks of the increasing leak rates on the unprotected steel infrastructure (Bay State Reply Brief at 9). The Company states that in New Hampshire, Northern Utilities did not need to use the geographic approach because of the small amount of bare and unprotected mains, as opposed to Bay State's more than 500 miles of bare and unprotected steel mains (Bay State Brief at 39).[29]

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[29] Regarding the bare steel replacement of Northern Utilities, which reduced the leak rate in New Hampshire, the Company claims that the decision referenced by the Attorney

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Regarding the "safety first" approach endorsed by the Attorney General, the Company asserts that it has never denied that prioritizing the worst performing segments for replacement is an appropriate method, adding that it has applied such method in its replacement decisions in the past (Bay State Reply Brief at 9, citing Tr. 15, at 2443). The Company states that the immediate replacement of dangerous pipes outside the geographic replacement zone will continue to take place to address the worst performing segments, while the incremental SIR program expenditures will address the accelerated geographic replacement of unprotected steel (Bay State Reply Brief at 9).

In response to the Attorney General's objections relating to the technical aspects of the SIR program, the Company asserts that the SIR program is not a "regulatory approach" but rather an operational approach that is already underway (Bay State Brief at 39). The Company asserts that the results of its comprehensive analysis done over a multi-year period by its experienced operations personnel were confirmed by R.J. Rudden (id. at 39-40).[30]

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[29] (…continued)
General also indicated that both Northern Utilities and the NHPUC recognized that the leak rate could reverse (Bay State Reply Brief at 8, n.5, citing Attorney General Reply Brief at 4). Bay State claims that such an approach is reactive to safety issues, not proactive, and is inappropriate for adoption as Bay State's replacement strategy (Bay State Reply Brief at 8, n.5).

[30] Regarding the Attorney General's claim that the R.J. Rudden study is biased because it recommends an annual spending in the range of $20 million that was initially indicated by the Company to R.J. Rudden, Bay State asserts that there is no evidence presented by the Attorney General that R.J. Rudden would endanger its professional integrity by altering its conclusions to meet a purported demand of a client (Bay State Brief at 40, n.24).

The Company asserts that it is not difficult to determine that corrosion is the root cause of widespread and increasing leakage (id. at 40). The Company notes that: (1) corrosion is reported on an annual basis to the U.S. Department of Transportation's Office of Pipeline Safety to comply with federal reporting requirements (id. at 40, citing Tr. at 3909-21, 3378); (2) corrosion is the leading cause of safety risks to the distribution system (id. at 40, citing Exh. BSG/DGC-17); and (3) a number of regulatory agencies have mandated replacement of bare and unprotected steel pipes for some or all of the gas companies operating in their jurisdictions (id. at 40, citing Exhs. DTE-5; DTE 2-16).

Contrary to the Attorney General's claim, Bay State contends that a root cause analysis will not produce any new information and value for Bay State (Bay State Brief at 40). The Company asserts that its decision to replace first in the Brockton system represents the prioritization of needed replacement in a broad, system-based context (id. at 38). Bay State asserts that its determination that the SIR program start in Brockton does not require any additional analysis, noting that the Brockton division accounts for 63 percent of all the bare steel and unprotected coated steel mains in the Bay State system (id. at 40).

The Company states that DOER does not question the need for the SIR program but recommends rejection of the SIR program cost recovery mechanism (id. at 41, 173). The Company claims that the absence of the SIR cost recovery mechanism will not provide a reasonable opportunity to recover the incremental costs of the SIR investments, prevents Bay State from earning its allowed rate of return, and would require Bay State to file new base rate cases to recover the SIR program cost (id. at 170-171). The Company claims that aside from

the lowered procurement costs for steel main replacement, the SIR base rate adjustment would avoid higher overall regulatory and administrative costs by avoiding base rate cases, all of which are goals of PBR (id. at 172; Bay State Reply Brief at 38). The Company also states that the O&M costs savings will be passed on to customers immediately, unlike in the case of less frequent base rate proceedings (Bay State Brief at 172).

The Company also claims that the PBR price cap index will not accommodate the rapidly increasing capital expenditures of the SIR program, because that index is based on past industry trends and that the capital requirements of the SIR program are not incorporated in that industry experience (Bay State Brief at 171, 188, citing Tr. 4, at 675-679; Bay State Reply Brief at 38). The Company claims that in situations like this a separate targeted rate recovery mechanism, outside of the PBR price cap index, is appropriate and consistent with PBR theory (Bay State Brief at 171, citing Tr. 4, at 680-681; Bay State Reply Brief at 38).[31]

The Company contends that the Attorney General is incorrect in his assertion, that the SIR base rate adjustment mechanism biases the inflation and productivity factors used in the price cap index formula, claiming that there is no record evidence to support such assertion (Bay State Brief at 188, citing Attorney General Brief at 37). The Company argues that the SIR base rate adjustment has been designed so that it does not double collect steel replacement

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[31] The Company notes, for example, that in Victoria, Australia, utilities were required to invest a large amount of capital over a relatively short period of time to replace all of their existing meters with interval meters and, because the intensive capital program was not included in the past capital spending experience of the utilities involved, an adjustment of the companies' PBRs was implemented to recover the costs of new meters (Bay State Brief at 171, 188, citing Tr. 4, at 679-681).

costs, which means that whatever rate adjustments result from the SIR are mathematically equivalent to the rate adjustments that would have occurred if those costs had instead been recovered through the Z factor under the PBR plan (Bay State Brief at 188-189). The Company adds that the Z-factor, like the SIR, is designed to collect company-specific costs that are not otherwise reflected in the price cap index parameters (id. at 189). Bay State states, however, that it did not propose to use the Z-factor to recover steel replacement costs because this factor has been defined more narrowly (id. at 189, citing Tr. 4, at 751-752). The Company concludes that because the SIR base rate adjustment mechanism has been designed to be mathematically equivalent to a Z-factor, it does not bias the productivity and inflation elements of the price cap index formula (Bay State Brief at 189).

The Company asserts that not all capital costs associated with mains, meters and services, included in the test year, will be recovered through the SIR base rate adjustment mechanism, but rather only the extraordinary portion of replacement of unprotected steel facilities will be recovered (Bay State Reply Brief at 46). The Company claims that the price cap index applies only to the portion of Bay State's test year rates, which excludes the accumulated costs of eligible steel replacement facilities, while the SIR base rate adjustment only recovers the costs of those eligible facilities that the Company has replaced since the test year (id.). The Company concludes that the price cap index and the SIR base rate adjustment are completely separate rate factors that apply to two different costs and, therefore, there is no double recovery of steel replacement costs (id.).

The Company claims that its annual base rate adjustment filing, which includes the calculations for the SIR base rate adjustment, only alters the timing of review of a portion of the Company's capital investments (id. at 12). The Company states that it is completely within the Department's discretion to determine and require the amount of information needed to support such a filing (id.). The Company believes that the review of such a filing would be consistent with that undertaken for plant investments in a general rate proceeding, and that it would permit the Department a timely and manageable annual filing (id.). The Company states that the approval of the SIR program will not cause other utilities to flock to the Department, claiming that there is no evidence on this record that other companies are similarly situated with regard to their infrastructure (id.).

D. Analysis and Findings

Two sets of issues were raised on the Company's proposed SIR program. The first relates to those issues regarding the Company's accelerated steel infrastructure replacement program initiated in 2004. The second relates to the Company's proposed SIR base rate adjustment mechanism. We address these two issues below: in doing so, we emphasize that the two issues are quite distinct, even though related in the Company's petition. The SIR is the Company's program for replacing aging plant. The base rate adjustment mechanism is the proposed means to account for SIR incremental investments. In the discussion below, we do not accept the proposed SIR base rate adjustment mechanism; but that by no means implies that the Department substitutes its judgment for the management's job as to how best to meet and fulfill its obligations to maintain and operate its system consistent with safety and economic

protocol especially in light of the specific representation by the Company that it would proceed with the SIR program regardless of the Department's decision regarding the rate adjustment mechanism.

1. Steel Infrastructure Replacement

The Company has embarked on a program that it characterizes as an accelerated replacement of its cathodically unprotected steel infrastructure, consisting of cathodically unprotected bare steel and cathodically unprotected coated steel mains and services and the associated facilities in its distribution system. These steel mains and services installed during the post-World War II construction boom are subject to corrosion, which is a primary cause of natural gas pipe leakages. Since the enactment of federal regulations that require natural gas pipelines installed after July 31, 1971 to be protected against external corrosion,[32] the Company has installed new and replacement plastic and cathodically protected steel pipes in compliance with this regulation (Exh. BSG/DGC-1, at 11-12; Tr. 14, at 2375-2376).

The Attorney General raised a number of concerns on the geographic approach applied by the Company and suggests that the Department direct the Company to apply the safety first approach. The record shows that the Company immediately repairs the most dangerous type of leaks (Type 1), and that it has an above-average record of leak backlog/repair performance at year-end since 1993 for Type 2 leaks (Exhs. BSG/DGC-1, at 9; AG 2-16(a); Tr. 6, at 1057-1060). In addition, the Company has represented and affirmed that it prioritizes

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[32] 49 C.F.R. § 192.455. Transportation of Natural Gas and Other Gas Pipeline: Minimum Federal Safety Standard Requirement, External Corrosion Control: Buried or Submerged Pipelines Installed After July 31, 1971.

the replacement of the worst performing segments of pipes for immediate replacement, even if these pipes are outside of the geographic replacement zone, under the Company's SIR program (Exh. BSG/DGC-1, at 9;Tr. 15, at 2443).

On the question of whether the safety first approach or the geographic approach is more cost effective, the Department notes that the cost of property damage or potential loss of life is the foremost factor in addressing this issue. Public safety is the foremost concern of regulated utilities and the Department. This agency, along with other state and federal regulatory agencies, ensures that companies adhere strictly to the laws and regulations on safety. The Company's past performance on leak backlog/repair performance is above-average (Exhs. BSG/DGC-1, at 9; AG 2-16(a); Tr. 6, at 1057-1060). The Company will continue to immediately repair the most dangerous type of leaks and prioritize the worst performing segments of pipes consistent with both its current practice and the geographic approach (Exh. BSG/DGC-1, at 9; Tr. 15, at 2443). The Department cannot discern, based on its review of the record in this case, any substantive difference between these two approaches.

The Department notes that the Brockton system ranks at the higher end of leak rate per mile among a total of 77 national and regional gas companies (Exhs. BSG/DGC-1, at 17; AG-2-16(a); Tr. 6, at 1061; see Tr. 2, at 281-284). In addition, the system operating pressure of Brockton is relatively higher than that for the Lawrence system and Springfield system (Exh. BSG/DGC-1, at 21-22; Tr. 6, at 1061). Also, the Brockton system accounts for a significant portion (63 percent) of the Company's total unprotected steel mains to be

replaced.[33] Accordingly, the Department considers it reasonable that the Company would start with the Brockton system in applying its preferred geographic approach for the replacement of unprotected steel infrastructure.

Although, at the outset, the geographic approach appears to be more efficient and cost-effective method of the replacement of unprotected steel infrastructure, the Department notes that there are many other factors not evident in this record that a gas utility company has to consider in its day-to-day activities to ensure safe and reliable service at a reasonable cost for its replacement program. In addition, the Department would review the prudence of any non-discretionary plant additions proposed to be included in rate base during a base rate case proceeding. Endorsing a specific method of replacing a utility's unprotected steel infrastructure would not only limit the utility management's operational flexibility, but also could encumber the Department's future prudence reviews. Accordingly, the Department will not direct a specific approach and will defer to the Company's management judgement to choose the appropriate approach for the replacement of its unprotected steel infrastructure, taking into account the paramountcy of public safety and the goals of efficiency and reasonable cost.

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[33] The Brockton division evolved from several separate corporations and numerous service area expansions over the years wherein most (63 percent) of the Company's unprotected steel infrastructure are situated (Exh. DTE-2B). See also Brockton-Taunton Gas Company, D.P.U. 13228 (1960); Brockton-Taunton Gas Company(Norfolk), D.P.U. 11258 (1955); Brockton Gas Light Company (Norwell), D.P.U. 3385 (1928); Brockton Gas Light Company (Easton), D.P.U. 1803 (1925); Taunton Gas Light Company (Norton), G&E 963 (1916).

The Attorney General raised two related issues concerning the pace of the Company's main replacement during the merger five-year rate freeze, compared to the pace of replacement before or after that period. The issues raised are: (1) whether the Company deferred its needed replacement of its unprotected steel infrastructure, in order to reduce its "historical" level of replacement that, consequently, would increase the annual incremental eligible facility investments that would be recoverable in the SIR annual base rate adjustments; and (2) whether the Company deferred its needed maintenance or replacement of its unprotected steel infrastructure, specifically in its Brockton division, that unduly jeopardized the safety aspect of its service obligations.

The Department notes that from 1985 to 2004, the Company reduced its inventory of cathodically unprotected bare steel and cathodically unprotected coated steel by 708 miles from 1,291 miles to 583 miles, for an average reduction of 37.3 miles per year during this 19-year period (Exh. BSG/DGC-1, at 17; RR-DTE-10, at Att. at 4). For the period from 1985 to 1998, prior to the merger five-year rate freeze, the Company reduced its inventory of cathodically unprotected bare steel and cathodically unprotected coated steel by 586 miles from 1,291 miles to 705 miles, for an average reduction of 45.08 miles per year over this thirteen-year period (RR-DTE-10, Att. at 4; see Exh. UWUA-4, at 26). However, during the merger-related five-year rate freeze from 1998 through 2003, the Company reduced its inventory of cathodically unprotected bare steel and cathodically unprotected coated steel by 90 miles from 705 miles in 1998 to 615 miles in 2003, for an average reduction of 18.0 miles

per year over this five-year period (RR-DTE-10, Att. at 4; see Exh. UWUA-4, at 27).[34] Thus, the Company's average annual reduction of its unprotected bare steel and unprotected coated steel main inventory during the pre-merger period was 2.5 times greater (=45.08/18.0) than the average annual reduction during the five-year rate freeze period.[35]

In the case of the Brockton division, the Department notes that from 1985 to 2004, the Company reduced its inventory of cathodically unprotected bare steel and cathodically unprotected coated steel by 443 miles from 811 miles to 368 miles, for an average reduction of 23.3 miles per year during this 19-year period (RR-DTE-10, at Att. at 4). For the period from 1985 to 1998, prior to the merger-related five-year rate freeze, the Company reduced its inventory of cathodically unprotected bare steel and cathodically unprotected coated steel by 374 miles from 811 miles to 437 miles, for an average reduction of 28.8 miles per year over this 13-year period (id.).

However, during the merger-related five-year rate freeze from 1998 through 2003, the Company reduced its inventory of cathodically unprotected bare steel and cathodically unprotected coated steel in the Brockton division by 47 miles from 437 miles in 1998 to 390 miles in 2003, for an average reduction of 9.4 miles per year (id.). Thus, the Company's

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[34] The Company indicated in its brief that from 1995 to 2004 it replaced 130 miles of cathodically unprotected bare steel and 213 miles of cathodically unprotected coated steel (Bay State Brief at 36-37, citing Exhs. AG 14-1; AG-14-25; RR-AG-95). These figures are consistent with those summarized in Record Request DTE-10, Att. at 4.

[35] After the post-merger five-year rate freeze (i.e., from 2003 to 2004), the Company reduced its unprotected bare and unprotected coated steel inventory by a total of 32 miles, which is almost twice (32/18=1.8) the average annual reduction during the rate freeze period (i.e., 1998-2003) (RR-DTE-10, Att. at 4).

average annual reduction of its unprotected bare steel and unprotected coated steel main inventory in the Brockton division during the 1985-1998 pre-merger period was 3.1 times greater (=28.8/9.4) than the average annual reduction during the five-year rate freeze period.[36]

Regarding the Company's consolidated leak rates, the average consolidated leak rate during the 1998-2003 merger rate freeze period was 2.31 times (=1.04/0.45) greater than the average leak rate of the pre-merger rate freeze period.[37] In the case of the Brockton division, the average leak rate during the 1998-2003 merger rate freeze period was 2.18 (=1.31/0.60) times the average leak rate of the pre-merger rate freeze period.[38]

The Company's stated primary basis and justification for its accelerated steel infrastructure replacement program are claimed accelerating leak rates (Exhs. BSG/SHB-1, at 36-37; BSG/DGC-1, at 15-17; Tr. 6, at 1056). However, despite the fact that the Company's average leak rate per mile during the five-year rate freeze period was 2.31 times

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[36] The year after rate freeze ended (i.e., 2003 to 2004), the Company reduced the unprotected bare and unprotected coated steel main inventory for the Brockton division by a total of 22 miles, or 2.3 times (22/9.4) the average annual reduction during the rate freeze period (RR-DTE-10, Att. at 4).

[37] The record shows that during the 1985-1998 pre-merger rate freeze period, the Company's consolidated average leak rate increased from 0.26 leaks per mile to 0.87 leaks per mile, for an average of 0.45 leaks per mile (RR-DTE-10, Att. at 4). During the merger rate freeze period, the Company's consolidated leak rate increased from 0.87 leaks per mile in 1998 to 1.25 leaks per mile in 2003, for an average of 1.04 leaks per mile (id.).

[38] The record shows that during the 1985-1998 pre-merger rate freeze period, the average leak rate for the Brockton division increased from 0.27 leaks per mile to 1.07 leaks per mile, for an average of 0.60 leaks per mile (RR-DTE-10, Att. at 4). During the merger rate freeze period, the Company's consolidated leak rate increased from 1.07 leaks per mile in 1998 to 1.54 leaks per mile in 2003, for an average of 1.31 leaks per mile (id.).

greater than the pre-merger period, the Company's pace of replacement during the rate freeze period was 2.5 times less than the pre-merger period.

A similar situation exists in the case of the Brockton division. More specifically, although the average leak rate during the rate freeze period was 2.18 times greater than the pre-merger average leak rate, the Company's pace of replacement during the rate freeze period was 3.1 times less than the pace of replacement during the pre-merger period. Accordingly, based on its review of the record in this case, the Department concludes that there was a significant slowdown in the Company's pace of replacement of its unprotected steel mains during the merger rate freeze period despite evidence of a significant increase in leak rate per mile during that same period compared to the pre-merger rate freeze period. We will not attempt on this record to infer intent from effect; but a retreat from the pre-merger replacement pace would have advantaged the corporate bottom line during the rate freeze period. A return during the test year to something closer to pre-merger pace would have had other advantages, intended or not.

Regarding the issue whether the Company unduly jeopardized safety in the operation of its distribution system, the record shows (and as noted above) that under the Company's current operational procedure it immediately repairs the most dangerous type of leak (Type 1) and that it has an above-average record of leak backlog/repair performance at year-end since 1993 for Type 2 leaks based on U.S. Department of Transportation ("DOT") data (Exhs. BSG/DGC-1, at 9; AG-2-16(a); Tr. 6, at 1057-1060). In addition, the Company performs comprehensive leak detection surveys on 100 percent of its mains on an annual basis,

a procedure that exceeds the requirements of both the DOT and the Department's regulations (Exh. BSG/DGC-1, at 8).

Thus, despite the above-noted slow down in replacement of its unprotected steel mains during the merger rate freeze period and the increased leak rates during that same period, the record shows that the Company appears to have managed to maintain not only an acceptable but an above-average leak backlog repair performance at year-end compared to other gas utility companies (Exhs. BSG/DGC-1, at 9; AG 2-16(a); Tr. 6, at 1057-1060;). Although the leak rates have increased, the total number of leaks has stabilized or decreased (Exh. AG 2-1, at 4; Tr. 6, at 1070; RR-DTE-10, at 4).[39] The Attorney General has not sustained his claim that the Company jeopardized safety in the operations of its distribution system as a result of the slowdown in the pace of replacing its unprotected steel mains during the merger rate freeze. Nonetheless, the record shows that while the Company appears to be managing its leak repair performance (Exhs. BSG/DGC-1, at 9; AG 2-16(a); Tr. 6, at 1057-1060), its leak rate is increasing (Exhs. BSG/DGC-1, at 16-17; AG 2-1; RR-DTE-10). The record thus demonstrates a need for continued vigilance by the Company regarding its steel infrastructure.

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[39] During the ten-year period from 1994 to 2004, for example, the total number of corrosion leaks in the Brockton service area decreased from 561 leaks in 1994 to 509 leaks in 2004, or a decrease of nine percent (Exh. AG 2-1, Att. at 4; Tr. 6, at 1070). The Company's consolidated number of leaks decreased from 693 leaks in 1994 to 674 in 2004, or a decrease of three percent (Exh. AG 2-1, at 4; RR-DTE-10, at 4).

2. SIR Base Rate Adjustment Mechanism

A number of parties have raised issues regarding the Company's proposed ratemaking treatment of the incremental annual costs of the SIR program to be recovered through a separate SIR program annual base rate adjustment mechanism. The issues relate to: (1) whether the proposed base rate adjustment itself is necessary and appropriate; and (2) if found necessary and appropriate, whether the proposed calculations are appropriate for such base rate adjustment, which includes the use of an "historic" average annual direct expenditures and the application of carrying costs from the date of service to the date when the plant is included in rates.

Regarding the first issue, the record shows that the Company's annual direct expenditures on unprotected bare steel and unprotected coated steel infrastructure from 1999 through 2004 were $5.7 million, $2.6 million, $5.2 million, $3.8 million, $4.6 million and $6.2 million respectively, for an average of $4.7 million during the 1999-2004 period or an average of $4.0 million during the 2000-2003 period (Exhs. BSG/JES-1, Sch. JES-17, at 3 (corrected); AG 17-13; DTE 3-33; RR-DTE-145).[40] Since the Company has proposed annual incremental direct expenditures of approximately $15.3 million (or approximately $20 million including overhead costs), this represents $19.3 million ($4.0 million + $15.3 million) in average annual total direct expenditures on the replacement of its unprotected steel

[40] The annual direct expenditures were broken down into mains, services, and other additions (Exhs. AG 17-13; DTE 3-33).

infrastructure. This amount is 4.8 times greater that the $4.0 million "historic" annual average direct expenditures for the 2000-2003 period indicated by the Company.[41]

The Department has found above that, despite the significant slow down in the pace of replacement during the merger rate freeze period and the corresponding increased leak rates during the same period, the Company has managed to maintain a safe operation of its distribution system. The Company has stated that it is committed to its accelerated SIR program and will continue with the program even if the Department were to deny its proposed SIR base rate adjustment mechanism (Exhs. BSG/SHB-1, at 36, 39-40, 44; BSG/DGC-1, at 22). The Department has ruled above that it will defer to the Company's management judgment to choose the appropriate approach for the replacement of its unprotected steel infrastructure. Likewise, the Department will defer to the Company's management judgment on the appropriate pace of replacing its unprotected steel infrastructure in order to provide ratepayers the greatest level of safety and reliability of service at the lowest possible cost.[42]

In addition, the Department notes that because the Company was able to replace its inventory of cathodically unprotected bare steel and unprotected coated steel prior to the merger rate freeze period at a much faster pace than during the rate freeze period, the Company can be reasonably expected to resume its original pace of replacement that occurred

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[41] The 2000-2003 period includes four years within the five-year rate freeze. The average annual direct expenditures during the five-year rate freeze period was $4.4 million (Exhs. AG 17-13; DTE 3-33).

[42] Bay State indicated that it plans to spend a total amount (including overhead costs) in excess of $25 million per year in non-revenue producing, non-discretionary SIR plant additions (Exh. BSG/SHB-1, at 39-40).

prior to the rate freeze without a base rate adjustment mechanism. From 1985 to 2004, Bay State's average replacement of unprotected bare steel and unprotected coated steel was 37.3 miles per year. Furthermore, prior to the rate freeze (1985-1998), the Company's replacement averaged 45.08 miles per year. Under the Company's SIR program, Bay State is proposing to replace 583 miles of cathodically unprotected bare steel and unprotected coated steel over 15 years, which is equal to an average yearly replacement of 38.9 miles. The proposed pace of replacement is on par with the replacement rate over the last 19 years and slower than the pace prior to the rate freeze.

The Company has stated that its SIR program is dedicated to the replacement of its unprotected steel infrastructure and stated that the investments in such programs are non-discretionary and non-revenue producing (Exh. BSG/SHB-1, at 39-40). The record shows that aside from taking a 50-year horizon in its pipe replacement, the Company considers potential growth in usage or increase in the number of customers as a basis for replacing its steel infrastructure with the appropriate dimensions to meet such an increase in demand (Exhs. DTE-3-21 (Rev.) (Project ID #BO4D5072); DTE-3-32, at 27, 39-41 (Project ID #B04D5052; Project ID #B03D5077); Tr. 12, at 1975-1976; Tr. 15, at 2490, 2493, 2498-2500).[43] Thus, while such replacement activities are considered non-discretionary, such investments could be revenue producing if and when such growth in demand materializes in the future (Tr. 5, at 907).

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[43] Exhibit DTE-3-32 provides the capital authorization and closing reports for all the SIR-related projects completed in 2004 with costs in excess of $50,000.

Regarding the issue relating to the proposed SIR base rate adjustment, which is separate from the proposed annual PBR base rate adjustment mechanism, the Department notes that the annual incremental expenditures for the SIR program at the projected total amount of approximately $20 million would be excluded from the costs that would be subject to the PBR price cap formula. Although the Company has stated that such expenditures are non-discretionary, exempting such a subset of costs from the structure of the PBR incentive mechanism would significantly reduce the costs subject to such an incentive mechanism.

Even if the plant additions to replace its unprotected steel infrastructure are considered non-discretionary, the Department must ensure that such plant additions are used and useful and prudent. D.T.E. 03-40, at 67 (2003), citing D.P.U. 85-270, at 20. The record of the Company's safety performance and backlog/repair ratio noted above serves to demonstrate how a utility could effectively manage its operations to obtain the lowest cost possible for its customers without jeopardizing safety. However, to the extent that the traditional cost of service/rate of return regulation for setting a utility's distribution rates were replaced by a PBR mechanism, exempting such subset of costs from such a PBR mechanism would dilute, if not defeat, the purpose of such a shift to an incentive regulatory paradigm.[44]

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[44] Non-discretionary incremental investments proposed for recovery through the SIR base rate adjustment mechanism could provide incremental revenues to the Company. The record shows that the Company's expert witness on its PBR proposal acknowledged that to the extent that there are incremental revenues associated with the incremental portion of the SIR program expenditures proposed for recovery, then the probability of the Company's earnings getting closer to the upper bandwidth of the earning sharing mechanism would be higher than the probability of such earnings getting closer to the lower end of such a bandwidth (Tr. 9, at 1487-1488). Therefore, the proposed SIR

(continued…)

Based on all the above reasons, the Department finds that the Company's proposed SIR base rate adjustment mechanism is not warranted. With this finding, we do not need to address such issues as those relating to the specifics of calculating the annual SIR base rate adjustment mechanism identified by the parties.

3. Conclusion

The Department notes that the Company has represented that it will continue with its SIR program even if the Department will not approve its base rate adjustment mechanism to recover the incremental costs associated with the acceleration of the replacement of its unprotected steel infrastructure (Exhs. BSG/SHB-1, at 36, 38-40; BSG/DGC-1, at 15, 22-23). Timely replacement of aging infrastructure addresses a problem that threatens public safety, and the integrity and reliability of the infrastructure built and maintained to serve the public. This is a function of Bay State's basic obligation: to ensure that it delivers natural gas to its customers through a safe and reliable system. This is consistent with and adheres to the Department's previous statement that a utility company's obligation to fulfill safety requirements is absolute. Bay State Gas Company, D.P.U. 92-111, at 10 (1992).

Although the Department has denied the Company's proposed SIR base rate adjustment mechanism, it also has approved a PBR plan with a ten-year instead of the proposed five-year term. Section IX.C.3, below. In the event and to the extent that the SIR program may cause

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[44] (…continued)
base rate adjustment could not be completely independent of the PBR base rate adjustment mechanism. Accordingly, such a SIR base rate adjustment calculated separately from the PBR base rate adjustment could bias the incentive structure of such a PBR mechanism in favor of the Company.

the Company's earnings to fall below the lower threshold of the earning sharing mechanism determined elsewhere in this Order and only to the extent that the Company's plant investment through careful and contemporaneous documentation meets the prudent, used and useful test, the Company may after five years from the date of this Order petition the Department for a one-time base rate adjustment arising solely from its accelerated steel replacement program. By allowing the Company the opportunity to make such a filing, the Department is not pre-approving any specific rate treatment or cost recovery for the Company's investment in its SIR program. It is a conditional opportunity to petition that is here described and nothing more.

In addition, the Company is directed to file annual status reports with the Department detailing the status and progress of its steel infrastructure replacement program including but not limited to: (1) the number of feet of unprotected bare and coated steel mains and services replaced during the preceding year, by division and on a consolidated basis; (2) the number by types (1, 2, 3) of corrosion and source (bare or coated steel) of leaks at year-end by division and on a consolidated basis; and (3) the number of corrosion by type and source of leaks that were repaired at year-end, for each division and on a consolidated basis. The Company in its compliance filing to this Order shall provide the Department the appropriate form that will be used by the Company in its required annual status filings to the Department, after consulting with the Director of the Department's Pipeline Engineering and Safety Division. We note that by its own admission the Company states it faces a systemic leak problem and has pledged that it will address that problem systematically through a long-range campaign of replacement

(Exhs. BSG/DGC-1, at 15-17; BGE/SHB-1, at 36-38). Pipeline safety obligations require that this pledge be redeemed.

III. REVENUES

A. Introduction

During the test year, the Company booked total operating revenues of $510,457,335 (Exh. BSG/JES-1, Sch. JES-4). For the purpose of setting distribution service rates and determining the revenue deficiency, the Company proposes to make three types of revenue adjustments: (1) adjustments to test year sales to account for normal weather and a calendar year (Exh. BSG/JAF-1, Sch. JAF-1-1, at 1); (2) removal of revenues that do not impact delivery service (Exhs. BSG/JES-1, Sch. JES-4; DTE-17-2); and (3) removal of revenues that are credited to the cost of service for items that are treated above the line (Exh. BSG/JAF-1, at 37-41). The Company's proposed revenue adjustments reduce test year revenues to $456,392,153. The Company's proposed adjustments are discussed below.

B. Adjustments to Test Year Sales

1. Company's Proposal

The Company proposes a weather normalization adjustment to revise the calendar-month sales volumes to reflect sales volumes that would be expected under normal weather conditions (Exhs. DTE 22-4; BSG/JAF-1, at 18). Bay State determines weather normalizing volume adjustments to firm sales volumes and transportation throughput for each of the temperature-sensitive rate classes, namely the Residential Heating and C&I High Peak

Period classes,[45] by identifying the temperature-sensitive portion of volumes for these rate classes and calculating how much more or less the monthly volumes would have been to that rate class if temperatures had been normal (Exh. BSG/JAF-1, at 21-22). The Company uses a 20-year data base of effective degree days ("EDD") in each of its service areas to determine customer load per EDD (id. at 19). The Company's proposed weather normalization adjustment reduces test-year revenues by $2,555,582 (id. at 20; Exh. BSG/JAF-1, Sch. JAF-1, at 1).

The Company proposes an annualization adjustment to its test year revenues to account for such things as the revenue impact caused by the difference between the number of days in a normal year and the number of billing days in the test year, and to account for the revenue difference between the amount of gas it delivered to customers during the test year and the amount of gas it billed to customers during the same period (Exh. BSG/JAF-1, at 14-15, 35). Specifically, the Company computes its proposed annualization adjustment as the difference between delivery service revenues booked in the test year and delivery service revenues based on normalized adjusted sales volumes at current rates, less the weather normalization adjustment (id., Sch. JAF-1-1, at 1). Bay State's normalized adjusted sales volumes include a revision to monthly billed sales in the test year to account for billing adjustments (e.g., cancelled bills), to correct sales from billing month volumes to calendar month volumes, and to reduce these sales by 3/4 of a February day's usage because year 2004 was a leap year and an average year contains 365.25 days (Exhs. DTE 22-4; BSG/JAF-1, at 14, 15, 29). The

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[45] Rate classes R-3, R-4, G-40, G-41, G-42, T-40, T-41, and T-42.

Company's proposed annualization adjustment reduces test-year revenues by $15,224,173 (Exh. BSG/JAF-1, Sch. JAF-1, at 1). In addition, the Company proposed to decrease operating revenues by $3,336,453 to account for the difference between direct and indirect Gas Adjustment Factor ("GAF") and Local Distribution Adjustment Factor ("LDAF") revenues booked during the test year and direct and indirect GAF and LDAF revenues calculated using normalized sales volumes for both firm and transportation customers (Exh. BSG/JAF-1, Schs. JAF-1-1, JAF-1-2; RR-DTE-143).[46]

2. Analysis and Findings

No party commented on the Company's adjustments to test year sales. The Department has consistently allowed for billing day adjustments to test year revenues to reflect the fact that a normal year consists of 365.25 days. See D.T.E. 03-40, at 9. Furthermore, the Department has historically permitted adjustments for unbilled revenues, which account for discrepancies between billing cycles and calendar months. Id., at 12. The Department finds that Bay State's proposed adjustment of actual EDDs for the month of February to reflect the fact that 2004 was a leap year is consistent with Department precedent (Exh. BSG/JAF-1, at 14-15). The Department further finds that the Company's adjustments to test year sales volumes to account for billing adjustments and the discrepancy between billing cycles and calendar months are

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[46] Total GAF/LDAF revenues booked in the test year are $330,234,671 (Exh. BSG/JAF-1, Sch. JAF-1-1, at 1, columns 2 and 4, lines 5-7). Total annualized and normalized GAF/LDAF revenues at current rates are $333,571,124 (Exh. BSG/JAF-1, Sch. JAF-1-1, at 2, columns 2-4, lines 5-7). $333,571,124 - 330,234,671 = $3,336,453.

consistent with precedent. Therefore, we approve of the Company's computation of annualized sales.

The Department's standard for weather normalization of test year revenues is well established. See D.T.E. 03-40, at 22; Boston Gas Company, D.P.U. 96-50 (Phase I) at 36-39; Boston Gas Company, D.P.U. 93-60, at 75-80. The Company's method to weather normalize test year revenues is consistent with Department precedent. Therefore, we approve the Company's proposed adjustment to reduce test year revenues by $2,555,582 to account for normal weather in the test year and to further reduce test year sales by $15,224,173 to annualize sales. Also, we approve the Company's proposal to decrease operating revenues by $3,336,453 to account for the difference between direct and indirect GAF and LDAF revenues booked during the test year and direct and indirect GAF and LDAF revenues calculated using normalized sales volumes for both firm and transportation customers.

C. Revenues Adjustments That Do Not Affect Delivery Service

1. Company's Proposal

The Company has proposed to reduce test year revenues by $3,874,467, representing the test year revenues derived from off-system sales (Exh. BSG/JES-1, Sch. JES-4). According to the Company, these revenues are non-firm revenues generated from selling upstream capacity and supply, which are passed back to firm gas service customers through the Cost of Gas Adjustment Clause ("CGAC") as a reduction to gas costs, and have no impact on delivery service revenues (Exh. DTE 17-2).

The Company proposes to reduce test year revenues by $329,961 associated with lost base revenues[47] ("LBR"), because both the costs and revenue recovery of these costs are passed through the Local Distribution Adjustment Clause ("LDAC") and have no impact on base rate revenue requirement (Exhs. BSG/JES-1, Sch. JES-4; DTE 17-2).

During the test year, the Company incurred net expenses totaling $988,819 relating to pretax carrying costs on deferred gas costs, deferred bad debt on gas costs, and LBR (Exhs. BSG/JES-1, Sch. JES-4; DTE 17-2). According to Bay State, the gas-related costs are recovered through the CGAC and the lost net revenues are non-recurring, and, therefore, the Company proposes an adjustment to increase test year revenues by $988,820[48] (Exhs. BSG/JES-1, Sch. JES-4; DTE 17-2).

Bay State booked test year revenues of $1,044,497 associated with the gas supply function of the Company's local production and storage assets (Exhs. BSG/JES-1, Sch. JES-4; DTE-17-2). The Company proposes an adjustment to increase test year revenues by $8,085,135, to reflect the fact that although these revenues are recovered in the CGAC, the Company's last rate case established the portion of those revenues that should be credited to the cost of service (Exhs. BSG/JES-1, Sch. JES-4; DTE 17-2).

Finally, Bay State proposes to reduce test year revenues by a net $18,974,308 to eliminate indirect GAF and annualized LDAF expenses, net of bad debt expense included in

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47 Lost base revenues are forgone revenues by the Company due to the implementation of demand-side management (or energy efficiency) programs.

48 The Company attributes the $1 discrepancy to the effect of rounding (Exh. DTE-17-2).

gas costs, as these are recovered through the CGAC and LDAF, and do not impact base revenue requirement (Exhs. BSG/JES-1, Sch. JES-4; DTE 17-3).[49]

2. Analysis and Findings

No other party commented on the proposed removal of revenues that do not impact delivery service rates. As in the case of non-firm revenues, off-system sales revenues are not directly associated with distribution base rates. See D.T.E. 03-40, at 16. In order to establish a representative level of annual revenues for the establishment of base rates, Bay State must remove off-system sales revenues from total operating revenues. Id. Accordingly, we accept Bay State's proposal to reduce test year revenues by $3,874,467.

After reviewing the record, the Department finds that the proposed removal of revenues for LBR, pretax carrying costs, local production and storage, Indirect GAF, and annualized LDAF revenues represent accounting entries to properly distinguish between gas delivery revenues and those revenues that do not impact the base rates. Accordingly, the Department approves the Company's proposals that reduce test year revenues by $10,230,314.[50]

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[49] Indirect GAF is made up of: (1) local production and storage (on-system LNG and propane plants) allocated to the gas supply function; (2) working capital associated with gas costs; and (3) bad debt associated with gas costs (Exh. BSG/JAF-1, at 36).

[50] $329,961 - $988,819 - $8,085,135 + $18,974,308 = $10,230,314.

D. Revenue Adjustments Credited to Cost of Service [51]

1. Special Contracts

a. Company's Proposal

During the test year, the Company booked $3,502,265 in special contract revenues (Exhs. BSG/JLH-2-2, at 15; DTE 21-9). The special contract revenues are credited to the cost of service because they are treated for ratemaking purposes as above the line (Tr. 19, at 3001). The Company proposes to increase the test year revenues by $418,748 associated with one special contract and by an additional $404,852 associated with a second special contract (Exhs. JLH-2-1, at 5; AG 1-99, AG 9-2(Confidential); RR-DTE-18; RR-AG-65).[52] The Company claims that these two contracts entitle the Company to increase the special contract prices in proportion to increases in its base rates (Exhs. JLH-2-1, at 5; AG 1-99, AG 9-2(Confidential); RR-DTE-18; RR-AG-65).

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[51] The Department notes that the Company has credited the following additional revenue items to the cost of service, for which the Company has proposed no adjustments to test year levels: late payment charges of $215,536; returned check charges of $27,736; gas property rental revenues of $16,890; IC rental revenues of $871,002; LNG tank lease revenues of $178,750; customer shut-off revenues of $93,975; locksmith service, warrant, and reactivation revenues increases totaling $46,525; special contract revenues of $3,921,013; and Outside Services & Pension/PBOP revenues of $5,630,282 (Exhs. BSG/JLH-2, Sch. 2-2, at 8-1; BSG/JAF-2, Sch. JAF-2-1, at 8).

[52] The Department notes that the proposed increase to test-year revenues serves to reduce the revenue requirement because the special contract revenues are credited to the cost of service.

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that in addition to the special contract revenue adjustments the Company has proposed, the Company identified a third contract with similar pricing provisions, under which the test year revenues would increase by $7,363 (Attorney General Brief at 53, citing RR-AG-59). The Attorney General contends that because this revenue increase is known and measurable, test year revenues should be increased by an additional $7,363 (id., citing Essex County Gas Company, D.P.U. 87-59 (1987)).

The Attorney General further asserts that several additional special contracts have price escalation features that resulted in post test year revenues increases that, on an annual basis, total $17,050 (id., citing RR-AG-59). The Attorney General requests that the Department increase test year revenues by an additional $17,050 to account for these contracts (id.).

ii. Company

The Company has indicated that it would include an adjustment for the $7,363 in its compliance filing (RR-AG-59). The Company disagrees with the Attorney General's proposal to further adjust revenues for the post test year revenue increases (Company Brief at 67-68). The Company claims that the post test year revenue increases do not meet the Department's standard for significant post test year adjustments for revenue growth (id. at 67). Rather, they constitute a normal ebb and flow of sales, and they are not known and measurable because they are based on the prior year's usage (id., citing, inter alia, D.T.E. 03-40, at 27).

c. Analysis and Findings

In determining the propriety of rates for the companies under its jurisdiction, the Department has consistently based allowed rates on test year data. D.T.E. 03-40, at 11 (2003); D.P.U. 87-59, at 3 (1987). The selection of an historical twelve-month period of operating data as a basis for setting rates is intended to provide for a representative level of a company's revenues and expenses which, when adjusted for known and measurable changes, will serve as a proxy for future operating results. D.T.E. 03-40, at 11.

The Company's reliance on Department precedent regarding significant post test year adjustments for revenue growth is not warranted in this instance, however. In D.T.E. 03-40, at 27, the Department stated that it does not normally make adjustments for a post test year change in revenues attributed to customer growth. However, the addition or deletion of a customer or a change in a customer's consumption, either during or after the test year, that (1) represents a known and measurable increase or decrease to test year revenues, and (2) constitutes a significant adjustment outside of the "ebb and flow" of customers, may warrant a departure from this standard practice. Id.

In the case at hand, the post test year revenue increases do not involve a change in load levels, but rather an increase in the rate charged under specific special contracts. Although the Company claims that the revenue adjustment proposed by the Attorney General is not known and measurable because it is based upon past usage, the Company has presented no evidentiary basis to support a finding that test year gas consumption by the special contract customers in

question is not a fair proxy for their future consumption. The test year gas consumption is the evidence.

With respect to the special contract revenue adjustments to which the Company has already agreed (adjustments in the amounts of $418,748, $404,852, and $7,363, as identified above), the Company is directed to revise these figures in accordance with the percentage base rate increase approved in this Order, and include the revised adjustments in its compliance filing in this proceeding. The Department finds that the $17,050 revenue adjustment proposed by the Attorney General represents a known and measurable post test year adjustment to revenues and, therefore, the Company shall increase its test year revenues by that amount in its compliance filing. Accordingly, in its compliance filing, the Company shall credit these special contract revenues to the cost of service as adjusted for the approved percentage base rate increase.

2. Energy Products and Services

a. Introduction

Energy Products and Services ("EP&S") is Bay State's integrated service business (Exh. BSG/SHB-1, at 51). Bay State offers the following services through EP&S: heating equipment repairs; water heater repairs; water heater and conversion burner rentals; heating equipment inspections; and heating equipment and water heater rentals, sales and installations (id. at 52).

The following is the list of businesses and services provided through EP&S, along with the ratemaking treatment of each.

(1) The Guardian Care Service Business provides service to customer-owned equipment (id. at 55). This business operates above the line; therefore, the revenues and expenses are included in the cost of service (id.).
(2) The Water Heater Rental Business provides customers the option to rent water heaters from Bay State at a fixed monthly rate and receive continuing service for the water heater (id.). This business operates above the line; therefore, the revenues and expenses are included in the cost of service (id.).
(3) The Boiler and Furnace Sales and Installation Business provides customers a one-stop location for boiler and furnace purchasing (id.). This business operates below the line; therefore, the revenues and expenses are not included in the cost of service (and where expenses are shared, they are fully allocated to this function) (id.).
(4) Annual Inspections provide customers with a safety and efficiency check of their heating systems (id.). This business is above the line and operates fully within the gas utility; expenses are fully allocated to this business segment, and all profits from this business benefit ratepayers for ratemaking purposes (id.).
(5) Fee for Service provides customers with heating equipment and water heater repairs on a fee-for-service basis, as long as resources from the Company are available to provide the service (id. at 56). This business is above the line; expenses are fully allocated to the business segment and all profits are recognized for ratemaking (id.).

The Company accounts for the EP&S costs on a fully allocated basis, which means that the Company tracks direct costs, direct fringes and overhead related to EP&S (id. at 56-57). Direct costs include direct labor, parts and materials, rental water heater lease expense and rental water heater and conversion burner depreciation expense (id. at 57). These costs are charged directly to the service activities as incurred (id.). Direct fringes include Company benefits, payroll taxes and liability insurance related to direct labor costs (id.). These costs are allocated by multiplying direct labor by the ratio of total Company fringes to total company payroll (id.). Overhead includes the costs which are directly charged or allocated between the total service activities and other utility activities (id.). The costs for total service activities are subsequently allocated among the individual service activities on the basis of direct labor (id.).

Bay State has included $5.7 million in profit from EP&S in the test year, which offsets expenses that otherwise would be borne by ratepayers (id. at 58).

b. Positions of the Parties

i. Attorney General

The Attorney General takes issue with the method that the Company uses to allocate the EP&S revenues booked above-the-line (Attorney General Brief at 73). The Attorney General states that these revenues are allocated using the DISTR allocation factor, which is the distribution demand based allocator used primarily to allocate distribution plant (id., citing Exh. AG-22-10, at 2). Further, the Attorney General states that the DISTR allocator allocates approximately 55 percent of the margin from the above the line EP&S revenues to the residential classes, even though EP&S customers are overwhelmingly residential (id., citing Exhs. BSG/JLH-2, Sch. JLH-2-2, at 51, lns. 11-12; BSG/JLH-2, Sch. JLH-2-2, at 70, ln. 1; RR-AG-61). The Attorney General argues that the EP&S revenues should benefit the customers that generate the revenue and should be directly assigned to the residential class (Attorney General Brief at 73). The Attorney General avers that to do otherwise would violate the Department's fairness principle (id.).

The Attorney General also claims that the Company increased fees and charges for several EP&S programs during the test year and in 2005, but failed to account for how these known increases affect the EP&S margins (id. at 74, citing RR-AG-56). The Attorney General states that Department precedent requires that known and measurable changes to test year data be included in revenue requirements (Attorney General Brief at 74). The Attorney General

argues that although the Company contends that test year volumes and customer counts are not representative of future levels, there is no evidence to back up this claim (id.). However, the Attorney General asserts that there is evidence that EP&S rates will be increased by $794,259 (id., citing RR-AG-56, at 2). Therefore, the Attorney General argues that the Company's revenue requirement should be reduced by this amount to provide the benefits promised by Bay State and lessen the magnitude of any subsidy provided by captive utility customers (Attorney General Brief at 74).

ii. Company

Bay State argues that the Attorney General's suggestion concerning the allocation of the EP&S revenues does not follow proper cost allocation principles (Bay State Brief at 154, citing D.T.E. 03-40, at 367 (2003)). The Company claims that the Cost of Service Study it performed assumes that EP&S revenues are an opportunity created by the existence of facilities and resources available on the Company's distribution system (Bay State Brief at 154). Therefore, EP&S revenues are allocated to each of the Company's rate classes based on the DISTR allocation factor, which is the same distribution demand allocator used to allocate distribution plant (id.). Bay State claims that this allocation is consistent with the Department's treatment of above the line service businesses (id. at 155, citing D.P.U. 92-111). The Company argues that margins generated by programs like EP&S benefit all of the Company's firm customers by permitting Bay State's fixed costs to be spread over a larger revenue base (Bay State Brief at 155).

Bay State states that the Attorney General's suggestion that the Company's revenue requirement be decreased to account for the increased fees and charges for EP&S programs does not comply with the Department's precedent standard for an adjustment to test year revenues (id. at 68). The Company argues that the Department's standard requires an extraordinary change from test year revenues beyond the normal ebb and flow of revenues (id.). Bay State claims that the Department has routinely declined to allow an adjustment for revenue growth occurring after the test year (id., citing D.T.E. 03-40, at 27 (2003); Massachusetts American Water Company, D.P.U. 88-172, at 9 (1989); Bay State Gas Company, D.P.U. 1122, at 47 (1982)). The Company argues that the Attorney General's proposed revenue adjustment does not constitute revenues outside the normal ebb and flow of revenues (Bay State Brief at 69).

In addition, the Company states that the Attorney General's proposed revenue adjustment is not representative of the expected revenue from the EP&S fee increases in the test year, because the test year volumes and customer numbers used in the Attorney General's adjustment are not representative of the declining conditions expected in the rate year (id., citing Exh. AG 9-45; RR-AG-56, at 1). Finally, the Company asserts that the Attorney General's proposed revenue adjustment does not take into account any corresponding cost increases that may occur after the test year resulting from changes in the EP&S business (Bay State Brief at 69). For these reasons, the Company claims that the revenue adjustment proposed by the Attorney General does not meet the Department's standards for a post test year revenue adjustment and should be rejected (id.).

c. Analysis and Findings

Regarding the allocation of the costs and revenues associated with EP&S, the Company has used the DISTR allocator to allocate both the costs and revenues associated with EP&S. The Department finds that this allocation method is reasonable, given the fact that the allocation of costs should mirror the allocation of revenues. This finding is also consistent with Department precedent regarding the treatment of above-the-line service businesses. See D.P.U. 92-111, at 91-93. Therefore, the Department rejects the Attorney General's request to directly assign the EP&S revenues to the residential rate classes and instead finds that the allocation method proposed by the Company for EP&S is allowed.

Regarding the post test year fee changes for EP&S, in determining the propriety of rates for the companies under its jurisdiction, the Department has consistently based allowed rates on test year data. D.T.E. 03-40, at 11 (2003); D.P.U. 87-59, at 3 (1987). The selection of an historical twelve-month period of operating data as a basis for setting rates is intended to provide for a representative level of a company's revenues and expenses which, when adjusted for known and measurable changes, will serve as a proxy for future operating results. Id.

The Company's reliance on Department precedent regarding significant post test year adjustments for revenue growth is not warranted in this instance, however. In D.T.E. 03-40, at 27, the Department stated that it does not normally make adjustments for a post test year change in revenues attributed to customer growth. However, the addition or deletion of a customer or a change in a customer's consumption, either during or after the test year, that (1) represents a known and measurable increase or decrease to test year revenues, and

(2) constitutes a significant adjustment outside of the "ebb and flow" of customers, may warrant a departure from this standard practice. Id.

In the case at hand, the post test year revenue increases do not involve a change in load levels, but rather an increase in the fees charged for various EP&S programs. Although the Company claims that the revenue adjustment proposed by the Attorney General is not known and measurable because it is based upon past usage, the Company has presented no evidentiary basis to support a finding that test year volumes and customer numbers for the EP&S programs in question are not a fair proxy for future costs. Therefore, the Department finds that the $794,259 revenue adjustment proposed by the Attorney General represents a known and measurable post test year adjustment to revenues and, therefore, the Company shall reduce its test year revenues by that amount in its compliance filing.

3. Service Fees

a. Company's Proposal

The Company proposes to reduce test year revenues and the cost of service by $34,855 to represent a proposed increase in Account Reactivation Fees from $15.00 to $20.00 during regular business hours, and from $20.00 to $30.00 during after hours (Exh. BSG/JAF-1, at 38).

The Company currently assesses a $35.00 Warrant Fee to defray the cost of obtaining a warrant when necessary to access a customer's property (id. at 40). The Company proposes to modify its Terms and Conditions to allow for a direct pass-through of the actual cost of the warrant (id.). According to the Company, based on actual test year expense for warrants, the

Company's proposal would result in a $7,270 decrease to test year revenues and the cost of service. The Company proposes to make this adjustment (id. at 40-41).

During the test year, the Company incurred $4,485 in locksmith services to gain access to its meters on 110 occasions (id. at 41). The Company is proposing to implement a Locksmith Fee in the amount of $40.00 to defray these costs (id.). Based on the number of locksmith service calls in the test year, the Company proposes to decrease test year revenues and the cost of service by $4,400 (id.).

The Company also proposes to increase its Meter Test Fee from $10.00 to $50.00 (id. at 39). This fee is charged to customers when a meter is tested upon the customer's request (id.). However, the fee is waived if the meter is found to be faulty (Exh. BSG/JAF-3, Sch. JAF-3-1, App. B). Because no customer-requested meter tests were performed during the test year, the Company proposed no adjustment to test year revenues and the cost of service.

b. Analysis and Findings

No party commented on the Company's proposal regarding the service fee adjustments that are credited to the cost of service. The Department has approved the proposed warrant, account reactivation, and locksmith service fees in Section VIII.D.1, below. Accordingly, we find that the Company's test year revenue adjustments for service fees are based on test year data and are known and measurable. Therefore, we approve the revenue adjustments as proposed by the Company.

IV. RATE BASE

A. Plant Additions

1. Introduction

Bay State classifies plant in two ways: (1) revenue-producing, or discretionary, which is plant associated with new customer or increased load, such as new mains; and (2) non-revenue producing, or non-discretionary, plant associated with activities necessary to maintain system safety and reliability or key processes, such as main replacements, peak-shaving plant, and information technology upgrades (Exh. DTE 16-18; Tr. 2, at 366, 371-372). As part of its initial filing, the Company identified each non-discretionary project closed to the plant[53] account between year-end 1991 and year-end 2004 that were greater than $100,000 (Exhs. BSG/DGC-1, at 41; BSG/DGC-8; BSG/DGC-9; BSG/DGC-10; BSG/DGC-11). Bay State also provided the work orders and closing reports associated with each non-discretionary project closed to Account 367 (Mains) between 1999 and 2004 that were greater than $50,000 (Exhs. DTE 3-21 (Rev.); DTE 3-21 (Supp.); AG 1-19 (Rev.), § 1).

In the case of non-discretionary plant additions and revenue-producing plant additions, the information provided a detailed summary of the year the project was undertaken, the name of the project, the location of the project, a description of the project (e.g., street name), the actual direct and indirect total main costs, the comparative estimated direct main costs, and the percentage of how much the actual cost deviated from the initial estimate (Exhs. DTE 3-21

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[53] Plant that has been completed and reclassified from construction work in progress to its respective plant accounts.

(Rev.); DTE 3-21 (Supp.); AG 1-19 (Rev.) § 1). The Company also provided an explanation for any differences between estimated and actual project costs associated with non-discretionary plant additions and revenue-producing plant additions in excess of $100,000 that exceeded ten percent (Exhs. BSG/DGC-8; BSG/DGC-9).

In the case of revenue-producing plant, Bay State determines the feasability of the project based on an evaluation of the construction and operating costs of the project in comparison to its anticipated revenues, producing an internal rate of return ("IRR") (Exh. BSG/DGC-1, at 43-44; Tr. 1, at 373-377). The Company compares the IRR to a "hurdle rate" (i.e., a threshold rate of return) to determine whether the project should be built (Exhs. BSG/DGC-9; DTE 3-23). Depending upon the nature of the project, the Company's current hurdle rates range between 8.6 percent and 14.2 percent (Exh. DTE 16-17; RR-AG-22).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that Bay State has failed to meet its burden of proof that a number of plant additions were prudent (Attorney General Brief at 45). First, the Attorney General identifies five revenue-producing projects for which the Company, in his view, provided no documentation to demonstrate that the project was initially economic (id., citing Exhs. DTE 3-22 (Rev.); DTE 3-27 (Rev.)).[54] In addition, the Attorney General notes that each

[54] These include Project Numbers L99D0052, B98D0093, L95D0023, B94D0068, and B94D0101 (Attorney General Brief at 45).

of these projects experienced cost overruns for which the Company provided no explanation (Attorney General Brief at 45). According to the Attorney General, merely identifying growth projects and submitting lists of costs and summary descriptions is inadequate justification for including these plant investments in rate base (Attorney General Reply Brief at 19). The Attorney General concludes that the Department must exclude from rate base the $762,210 cost of the five projects, because the Company did not provide clear and cohesive evidence that these capital expenditures were prudently incurred (Attorney General Brief at 45-46; Attorney General Reply Brief at 19).

In addition to these projects, the Attorney General maintains that 21 out of 34, or 60 percent, revenue-producing projects costing $50,000 or more experienced cost overruns (Attorney General Brief at 46, citing Exhs. DTE 3-22 (Rev.); DTE 3-27 (Rev.)). Of those 21 projects, the Attorney General identifies 14 projects that had cost overruns which exceeded their original estimate by more than 20 percent (id.).[55] The Attorney General maintains that the extent of Bay State projects with cost overruns demonstrates that the Company has a difficult time adequately estimating project costs, staying on budget, and mitigating significant cost overruns (Attorney General Brief at 47). Accordingly, he recommends that the Department exclude the $4,474,078 cost of these projects from rate base because of the Company's inability to control costs (id. at 47; Attorney General Reply Brief at 19).

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[55] These include Project Numbers L2000D0022, B98D0065, B98D0125, S98D1038, S98D1087, L97D0013, L97D0016, S95D1040, College Highway, B01D0041, B99D0121, S99D1064, S99D1091, and L98D0055 (Attorney General Brief at 46).

Finally, the Attorney General references 181 non-discretionary capital projects which experienced significant cost overruns (Attorney General Brief at 47-48, citing Exhs. DTE 3-21 (Rev.); DTE 3-21 (Rev. Supp.); AG 1-19).[56] Despite the Company's claims that these projects are non-discretionary in nature, and thus must be completed regardless of associated cost overruns, the Attorney General maintains that the Company has an obligation to manage these projects well in order to avoid significant cost overruns (Attorney General Brief at 47; Attorney General Reply Brief at 20). In his view, the Company had no effective policy of containing or controlling these costs (Attorney General Brief at 47). The Attorney General maintains that the Company's policy of providing management with explanations of cost overruns is not a cost containment measure, but merely a way to identify problems to prevent them from happening in the future (id., citing Tr. 21, at 3388). Moreover, the Attorney General accuses the Company of not evaluating these projects with the intention of containing or mitigating costs as they exceed budget (Attorney General Brief at 48). He concludes that the Department should remove all cost overruns from rate base associated with the Company's nondiscretionary projects listed in Exhibits DTE 3-21 (Rev.); DTE 3-21 Rev. Supp.; and AG 1-19 (id.; Attorney General Reply Brief at 20).

b. Company

Bay State rejects the Attorney General's position that $762,210 associated with five revenue-producing projects which experienced cost overruns should be excluded from rate base

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[56] Although the Attorney General did not specifically provide the number of projects or otherwise identify them on brief, examination of the referenced exhibits demonstrates a total of 181 projects would be affected by his proposal.

(Company Brief at 47). As an initial matter, the Company notes, consistent with industry practice, it does not require a formal detail cost overrun write-up reports for projects where the final cost exceeds budget by less than ten percent (id. at 47-48, citing Exhs. BSG/DGC-1, at 42; DTE 16-19; DTE 16-13). Bay State points out that the total cost overrun of the five projects was $18,347, an average of less than $3,700 per project or a 4.7 percent cost overrun (Company Brief at 48, citing Exhs. DTE 3-22 (Rev.); DTE 3-27 (Rev.); RR-DTE-136). Finally, the Company notes that the cost overruns were more than offset by exceeding the number of customer additions, load addition or revenue additions, which resulted in all but one of the projects providing benefits to ratepayers by yielding post-construction IRRs greater than the Company's weighted cost of capital and internal hurdle rate (Company Brief at 48, citing Exhs. DTE 3-22 (Rev.); DTE 3-27 (Rev.); RR-DTE-136; Tr. 2, at 384; Company Reply Brief at 14-15).

With regard to the Attorney General's proposed elimination of 14 projects costing a total of $4,474,078, the Company points out that ten of the fourteen projects with cost overruns of greater than 20 percent have rates of return that exceeded the Company's weighted cost of capital and internal hurdle rate and are in service providing benefits to ratepayers (Company Brief at 49, citing Exhs. DTE 3-22 (Rev.); DTE 3-27 (Rev.); RR-DTE-136; Company Reply Brief at 15). With respect to the remaining four projects, the Company maintains that uncontrollable, unforeseen outside factors resulted in the cost overruns and the resulting IRRs below the hurdle rate (Company Brief at 49). The Company notes that the vast majority of projects about which the Attorney General complains exceeded the internal hurdle

rate for post-construction returns, even if the cost estimating process resulted in a variance from actual costs due to unforseen factors (id.). Moreover, Bay State contends that its cost control measures were in place on each project (id., citing RR-AG-87; Tr. 15, at 2450, 3463, 3721). Because Bay State considers that reasonable steps were taken to provide reasonable cost estimates and it claims the record contains no evidence of imprudence, the Company concludes that the Attorney General's proposal must be rejected (Company Brief at 49-50).

Concerning the Attorney General's proposed reductions for non-discretionary plant, Bay State maintains that it has controlled costs on non-discretionary projects, and the cumulative evidence in the record provides a "clear and cohesive reviewable evidence" on the additions in question (id. at 45 citing Massachusetts Electric Company. D.P.U. 95-40 (1995); Boston Gas Company, D.P.U. 93-60 (1993); The Berkshire Gas Company, D.P.U. 92-210 (1993)). The Company notes that, in addition to the cost and variance information provided in Exhibits BSG/DGC-8, DTE 3-21 (Rev.), DTE 3-21 (Supp.), and AG 1-19 (Rev.), it has supplied detailed data on the various steps taken to ensure that costs are controlled and mitigated (id. at 45-46, citing Tr. 15, at 2450; Tr. 21, at 3394, 3399; RR-AG-87). Moreover, the Company observes that, while contractors do not bid on the basis of time and materials, it does allow for reasonable changes for unforeseen conditions which, in the Company's view, is the primary basis for any variance (id. at 46, citing Exhs. DTE 3-21 (Rev.); DTE 3-21 (Supp.); AG 1-19 (Rev.) § 1; Tr. 15, at 2448; Tr. 21, at 3463; Company Reply Brief at 15). Accordingly, the Company concludes that the Attorney General's position on this matter must be rejected (Company Brief at 45; Company Reply Brief at 15).

3. Analysis and Findings

a. Introduction

For costs to be included in rate base, the expenditures must be prudently incurred and the resulting plant must be used and useful to ratepayers. D.P.U. 85-270, at 20. The prudence test determines whether cost recovery is allowed at all, while the used and useful analysis determines the portion of prudently incurred costs on which the utility is entitled to earn a return. Id. at 25-27.

A prudence review involves a determination of whether the utility's actions, based on all that the utility knew or should have known at that time, were reasonable and prudent in light of the extant circumstances. Such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the Department merely to substitute its own judgment for the judgments made by the management of the utility. Attorney General v. Department of Public Utilities, 390 Mass. 208, 229 (1983). A prudence review must be based on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances which were known or reasonably should have been known at the time a decision was made. D.P.U. 93-60, at 24-25; D.P.U. 85-270, at 22-23; Boston Edison Company, D.P.U. 906, at 165 (1982). A review of the prudence of a company's actions is not dependent upon whether budget estimates later proved to be accurate, but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time.

Massachusetts-American Water Company, D.P.U. 95-118, at 39-40 (1996); D.P.U. 93-60, at 35; Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A at 26 (1985).

The Department has also found that a gas utility need not serve new customers in circumstances where the addition of new customers would raise the cost of gas service for existing firm ratepayers. D.T.E. 03-40, at 48 (2003); D.P.U. 88-67 (Phase I) at 282-284. The Department stated that existing customers receive benefits whenever, all other things being equal, the return on incremental rate base exceeds the company's overall rate of return. Boston Gas Company, D.P.U. 89-180, at 16-17 (1990).

The Department has cautioned utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. D.P.U. 95-40, at 7 (1995); D.P.U. 93-60, at 26; D.P.U. 92-210, at 24; see also Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, at 304 (1978); Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, at 24 (1967). In addition, the Department has stated that:

> In reviewing the investments in main extensions that were made without a cost-benefit analysis, the Company has the burden of demonstrating the prudence of each investment proposed for inclusion in rate base. The Department cannot rely on the unsupported testimony that each project was beneficial at the time the decision was made. The Company must provide reviewable documentation for investments it seeks to include in rate base.

D.P.U. 92-210, at 24 (1993).

The Attorney General challenges the inclusion in rate base of the following three categories of revenue- and non-revenue producing projects: (1) five projects with cost

overruns and no cost/benefit analysis; (2) 14 revenue-producing projects with cost overruns exceeding 20 percent; and (3) cost overruns associated with 181 non-discretionary projects for which he alleges the Company failed to demonstrate cost-containment efforts. Each category is discussed below.

b. Revenue-Producing Projects Without Cost-Benefit Analyses

Concerning the five projects with cost overruns but no supporting cost-benefit analysis, each of the projects identified by the Attorney General has post-construction cost overruns ranging from two percent to nine percent of the original project estimate (Exhs. DTE 3-22 (Rev.); DTE 3-27 (Rev.)). As previously noted, Bay State does not require formal detailed cost overrun write-ups for projects less than $50,000, or where the final costs exceed budget by less than ten percent (Exhs. BSG/DGC-1, at 42; DTE 16-13). The Company's variance authorization threshold strikes a reasonable balance between the need for effective management oversight on project cost overruns and the need to avoid becoming distracted by variances in low-cost projects that could easily exceed a ten percent threshold.

In the case of Projects L99D0052 and B98D0093, the pre-construction IRR of 12.0 and 11.0 percent, respectively, exceeded the hurdle rate of 8.75 percent (Exh. BSG/DGC-9). Projects L95D0023 and B94D0101 had pre-construction IRRs of 21.0 and 13.0 percent, respectively, which exceeded their hurdle rates of 9.58 percent and 8.75 percent, respectively (Exh. DTE 3-27 (Rev.), at 2-3). The post-construction rates of return associated with these projects range from ten percent to 16 percent (Exhs. DTE 3-22 (Rev.); DTE 3-27 (Rev.)). These rates of return were all above the Company's hurdle rates in effect at the time of

construction (Exh. DTE 16-17; RR-AG-22). Therefore, the Department finds these costs were prudently incurred. See, e.g., D.P.U. 96-50 (Phase 1) at 15-25 (1996). Accordingly, the Department will include the cost of Projects L99D0052, B98D0093, L95D0023, and B94D0101 in rate base.

In the case of Project No. B94D0068, which was completed on October 13, 1994, the internal hurdle ROR was 8.55 percent, with a pre-construction IRR of 13 percent (Exh. DTE 3-27, at 3). The work order authorizing the project indicated that it was intended to provide natural gas to 30 new homes (Exh. DTE 3-27, List No. 15). The Department has allowed gas companies to take into consideration anticipated growth in their estimates of the benefits to be realized on the incremental rate base required to serve new customers. D.T.E. 03-40, at 55 (2003); D.P.U. 96-50 (Phase I) at 23 (1996). At the time the project was initiated, it was economically viable, as indicated by a pre-construction IRR greater than the internal hurdle rate. The Department's review of the supporting documentation leads us to conclude that Bay State acted prudently in estimating the throughput and costs associated with this project. Accordingly, we will allow the cost of this project in rate base as well.

c. Projects With Cost Overruns Exceeding 20 Percent

With regard to the second proposed adjustment, the cost overruns for the 14 projects identified by the Attorney General range from 22 percent to 185 percent (Exhs. DTE 3-22 (Rev.); DTE 3-27 (Rev.)). The Attorney General contends that Bay State's explanations for cost overruns are insufficient to demonstrate that the Company is effectively managing its capital costs. Bay State competitively bids all projects in excess of $50,000, on the basis of

unit prices versus time and material agreements, with allowance for unforeseen conditions, thus providing contractors with incentives to control their own costs (Tr. 15, at 2450-2451). The Company's large project bid process requires soliciting bids from four to eight approved bidders, depending on the work site (Tr. 15, at 2450-2451). Company inspectors provide contractors with daily field reports, denoting each day's work and identifying extra charges allowed for that day (Tr. 15, at 2450; Tr. 22, at 3721). The Company engages in active negotiation with communities regarding permit conditions in order to obtain the most favorable and cost-effective terms (Tr. 21, at 3394). The Company also regularly meets with city and town officials in order to discuss the extent to which municipal decisions, such as the imposition of permit conditions or other practices, affect the costs to Bay State and its ratepayers (id. at 3399). The Department finds that the Company has provided sufficient, clear and reviewable evidence to demonstrate that it has controlled costs and that the project expenditures were prudent. Based on this information, the Department also finds that the Company has engaged in appropriate cost-containment measures.

In addition to its cost containment policies, Bay State provided an explanation for the cost overrun associated with each of the 14 projects in question. These include, for example: (1) the presence of ledge and boulders that required the use of special removal equipment and backfilling with gravel and sand; (2) unavoidable construction delays, such as those caused by the onset of winter and the need to coordinate construction with the municipality; (3) road reconfigurations; (4) changes in scope of work required by both the Company and developers seeking service; and (5) costs of additional police details (Exhs. DTE 3-22 (Rev.) at 17, 30,

50, 55, 72; DTE 3-27 (Rev.) at 9, 18, 23, 29, 34, 45, 50, 73, 93). Moreover, ten of the 14 projects have rates of return that exceeded the Company's weighted cost of capital and IRRs (Exhs. DTE 3-22 (Rev.); DTE 3-27; RR-DTE-136). Although three projects (Projects L97D0016, College Highway, and S99D1091) had post-construction rates of return below the respective hurdle rates, their pre-construction rate of return exceeded the hurdle rate, and the reasons for construction overruns include ledge, high groundwater, and the need for additional mains (Exh. DTE 3-27 (Rev.), at 46-50, 69-72, 91-95). The Department's review of the supporting documentation leads us to conclude that Bay State acted prudently in estimating the costs associated with these projects.[57] Accordingly, we will allow the costs of these projects to be included in rate base.

With respect to Project No. S95D1040 (Palmer/Mount Dumpling Road), the work order that authorized the project indicated an IRR of 9.58 percent, a pre-construction IRR of 9.21 percent, a post-construction rate of return of 7.0 percent, and a cost overrun of 93 percent (Exh. DTE 3-27 (Rev.) at 3, 70 and 73). The work order further indicates that the project is a "growth" project for residential customers which had been evaluated by the Company's marketing department over a three-year period (id.). The Department has found that a gas utility is not required to service new customers in circumstances where the addition of new customers would raise the cost of gas service. D.T.E. 03-40, at 48 (2003); Boston Gas

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[57] There is no evidence that underestimated materials costs associated with the College Highway project was the result of imprudence, or would have affected the Company's decision to serve the associated condominium development (Exh. DTE 3-27 (Rev.) at 93).

Company, D.P.U. 88-67 (Phase I) at 282-283 (1988). Bay State, in this instance, failed to meet the Department's standard because the pre-construction rate of return was less than the IRR and the post-construction rate of return was less than the Company's weighted cost of capital, resulting in an increase in the cost of gas service to remaining customers. Therefore, we find that these costs were imprudently incurred. Accordingly, the Department will exclude the Palmer/Mount Dumpling project from the Company's rate base.[58]

d. Non-Discretionary Projects

Non-discretionary, non-revenue producing plant refers to "plant additions primarily intended to meet a utility's continuing service to its customers." D.T.E. 03-40, at 63. The cost must be prudently incurred and the resulting plant must be used and useful to ratepayers in order to qualify for rate base inclusion. Id. at 67. Of the 181 projects questioned by the Attorney General, 121 of these projects experienced cost overruns ranging from 11 percent to 439 percent; the remaining 60 projects had cost overruns or underruns ranging from minus 67 percent to 9 percent (Exhs. AG 1-19; DTE 3-21 (Rev. and Supp.); DTE 3-31 (Rev.)). For each of the 121 projects that experienced cost overruns greater than ten percent, the Company explained that the cost overruns were due to conditions unforeseen when the project costs were estimated. These included, for example: (1) exposure of mains in poor

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[58] A corresponding reduction of $13,928 in the Company's depreciation reserve is warranted, based on the in-service date of August 16, 1996 and depreciation rates in effect during this time for this type of main (Exhs. AG 1-24; AG 5-1; AG 5-3). The Department will also reduce the Company's deferred income tax reserve by $12,190, representing the tax depreciation of $45,006 less book depreciation of $13,928, multiplied by the combined tax rate of 39.225 percent.

condition requiring replacement; (2) the presence of ledge and the attendant costs of trenching, hauling and backfilling with gravel, sands, and other suitable fill material; (3) conditions imposed by the local municipality that expanded or modified the scope of a project from the original estimate; (4) the need to coordinate construction efforts with other utilities and the municipality; and (5) unexpected findings during construction (id.).[59]

A description of Project No. S02D1018, located in Springfield, serves to illustrate the the issues that may arise during construction. This particular project was intended to replace a section of ten-inch cast iron main in poor condition (Exh. DTE 3-21 (Rev.) at 121-137). The Company explained that:

> The estimate of $36,076 was prepared based on replacement with a 10" plastic pipe, but considering the new source regulator nearby, the main size was increased to 12" to improve gas flow into the distribution system. Once exposed, a portion of the cast iron main was observed to be graphitized, a condition requiring immediate replacement. The project was extended to remove the poor quality pipe. No costs were included in the estimate for tie-ins to mains in side streets. Main Street in Springfield is Route 116. When the permit to work in Main Street was issued, it included conditions requiring Bay State to saw cut the street, remove all excavated soils and backfill using flowable fill. None of these costs were anticipated. Early snow in the fall of 2003 caused the job to be shut down in progress. Additional contractor costs were incurred because of the project shutdown and restart.

(id. at 127).

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[59] For example, Bay State reports that during construction on a project in South Hadley, a cistern was uncovered, necessitating inspection and documentation by the town's historical commission (Exh. DTE 3-21 (Rev.) at 367). In addition, the Company uncovered human bones while excavating for a project in Walpole (id. at 613).

The Department's review of the supporting documentation leads us to conclude that Bay State acted prudently in estimating the costs associated with these 181 projects. Accordingly, we will allow the cost of these projects to be included in rate base.

B. Customer Information System

1. Introduction

The Company's Miscellaneous Intangible Plant Account 303 includes, among other plant items, a Customer Information System ("CIS") (Exh. BSG/DGC-1, Sch. DGC-11). According to the Company, its legacy customer information system was exceptionally difficult to upgrade for any purpose and posed a threat to the integrity and continuity of Bay State's operation and administration in the face of Year 2000 ("Y2K") computer concerns (Exhs. BSG/DGC-1, at 54; DTE 16-25; RR-DTE-109). Therefore, Bay State adapted the customer information system used by its affiliate, Northern Indiana Public Service Company ("NIPSCo"), customizing it to meet the Company's needs (Tr. 15, at 2528). The Company installed the CIS in November, 1999 (id.; Exh. BSG/DGC-1, at 54).

The CIS is a broad-based customer information system that supports the collection, processing, storage, and retrieval of customer service data for both the Company's 285,000 customers and Northern Utilities' 50,000 customers, including meter reading, billing inquiries, payment options, service orders, credit and collection, marketing information, and other information requirements (Exh. BSG/DGC-1, at 54-55). The installed cost of the CIS was $15,403,324 (Exh. BSG/DGC-11, at 1). During 2000 and 2001, an additional $6,142,735 was spent for CIS Pro-Edits, the cost of converting data from the former customer information

system to CIS (id.; Exh. DTE 16-25). Therefore, the total cost of the project was $21,546,059.[60]

In support of its contention that the CIS was a cost-effective system, the Company refers to a study conducted in 2005 by the META Group ("META Study") that compared the implementation costs of customer information systems for 38 gas, electric, and combination utilities across the country, grouped into small, medium and large categories (Exh. AG 3-16 (Supp.)). The Company states that the META Study concluded that Bay State's CIS costs were reasonable on a per-bill basis by comparison to group of companies studied (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General first notes that non-discretionary or non-revenue producing plant investments like the CIS must be evaluated under the used and useful standard (Attorney General Brief at 43, citing D.T.E. 03-40, at 82 (2003)). He then asserts that the Company made no effort to control or contain costs associated with the CIS project (id., citing Exh. BSG/DGC-11, at 1). To support this contention, he observes that the cost of the CIS was estimated at $8,101,600, consisting of $7,000,000 for the new software and an additional $1,101,600 to convert the existing database (Attorney General Brief at 43). However, the Attorney General states that the final cost of the project was $21,546,059, more than two and one-half times the original estimate (id. at 43-44, citing Exh. BSG/DGC-11, at 1, List Nos. 5

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[60] An additional $371,064 in CIS enhancements were installed during 2002 and 2003 to meet additional post-installation requirements identified through actual operating experience (Exh. BSG/DGC-11, at 2).

and 6). The Company, in his view, provided no explanation for the $13 million cost overrun (id. at 44, citing Tr. 15, at 2545-2546).

The Attorney General also observes that there was no competitive bidding on the CIS project, but instead, the Company chose IBM Global ("IBM") because that vendor knew the system and was in a better position to "leverage off" that knowledge base (id., citing Tr. 15, at 2545). The Attorney General concludes that the choice of vendors was unwise because it did not lead to lower costs, but rather costs which were two and one-half times the original estimate of the CIS project (Attorney General Brief at 44).

The Attorney General challenges the Company's reliance on the META Study that compared the implementation costs of customer information systems for groups of small, medium and large utilities all over the country (Attorney General Reply Brief at 18, citing Exh. AG 3-16 (Supp.)). In particular, he questions the propriety of comparing Bay State to small utilities, because the CIS technology installed was derived from, and is an extension of, NiSource's system, a much larger company (id. at 18-19, citing Tr. 15, at 2528-2530). In the Attorney General's view, the costs to implement this technology would be more appropriately compared to companies in the large utility grouping of the META Study (Attorney General Reply Brief at 19). That comparison, notes the Attorney General, produces a cost per meter adjusted for inflation of $74.59, which is more than double that of five of the seven other companies in the study (id.). Based upon these facts, he concludes that the CIS investment was neither reasonable nor resulted in a lower cost per bill issued on a forward looking basis (id.).

The Attorney General concludes that the entire $21,546,059 cost of the CIS project must be excluded from rate base as imprudently incurred (Attorney General Reply Brief at 18). On his arguments that the Company: (1) made no effort to determine whether there was a lower cost alternative; (2) failed to put the project out to bid in compliance with the Department's Order in D.T.E. 03-40, at 84 (2003);[61] and (3) completed the CIS project with a final cost of two and one-half times the originally estimated cost (id.). The exclusion of this plant expenditure, according to the Attorney General, would be consistent with the Department's actions in Massachusetts-American Water Company, D.P.U. 95-118, at 45-46 (1996) and D.P.U. 93-60, at 27-29 (1993), where it excluded from rate base costs associated with the imprudent solicitation of vendors (Attorney General Brief at 43).

b. Company

Bay State argues that the Attorney General's proposed adjustment to reduce rate base by the $21,546,059 plant investment in the CIS has been grossly overstated (Company Brief at 56). The Company claims that the amount included in rate base in this case is $11,182,919, the original cost of the CIS less accumulated depreciation, not the gross investment in the property (id.). For this reason alone, concludes the Company, the Attorney General's recommendation must be rejected (id.).[62]

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[61] In its order in that case, the Department stated that the competitive bidding process is one important means to measure whether a utility has controlled costs. The order was issued in 2003, while the project was initiated in 1999.

[62] The Attorney General later agreed that the exclusion from rate base should be limited to the net plant investment associated with the CIS (Attorney General Reply Brief at 19).

Turning to the Attorney General's remaining arguments, Bay State maintains that the record in this case shows that the Company needs the CIS, its decision to obtain an upgrade was necessary because of Y2K concerns, and the CIS continues to be used and useful in service for the benefit of its customers (id., citing Exh. AG 3-16 (Supp.); RR-DTE-109; RR-DTE-113). The Company points out that the CIS required fast action and critical implementation timing in 1999 to meet widespread Y2K concerns (Company Reply Brief at 13, citing Tr. 15, at 2529-2584). In view of that need for quick action, the Company argues that it chose the CIS because of the Company's familiarity with that software through its NIPSCo affiliate, and its judgment that this would allow the CIS to be placed into service in less time (id.).

The Company argues that the META Study supports this decision, by finding that the total investment in the CIS was reasonable compared to similarly sized gas utilities and resulted in a lower cost per bill issued on a forward looking basis (Company Brief at 56). Moreover, the Company disagrees with the Attorney General's position that the META Study should have compared Bay State to larger companies (Company Reply Brief at 13-14). According to the Company, the CIS installed at Bay State was not used by the Columbia Energy Group after the NiSource/Columbia merger and, thus, Bay State did not benefit from the economies of scale and lower per unit costs that inure to larger utilities (id.).[63] Therefore, the Company concludes that because customers do benefit from this plant addition in a manner that is a reasonable

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[63] NiSource acquired Columbia Energy Group and its five gas distribution subsidiaries on November 1, 2000 for an aggregate consideration of approximately $ 6 billion (Exh. AG 1-2(1)(2000 Form 10-K at 3)).

alternative to traditional, pre-investment cost-benefit analysis, the CIS plant addition meets the Department's standard for inclusion in rate base (Company Brief at 56-57, citing D.T.E. 03-40, at 54-56).

Bay State further argues that it made every effort to control costs, but that this type of information system has a long history of creating implementation challenges for utilities (Company Brief at 57). In order to control costs, the Company points out that it has a comprehensive review policy which includes prioritizing all projects, a review by NiSource's Chief Information Officer of all capital projects exceeding $100,000, and a complete business case analysis for capital projects greater than $300,000 which have gone through the Company's information technology review process and have been designated as "Priority 0" (i.e., high priority projects) (id. at 55, citing Exh. BSG/DGC-1, at 47-48; Company Reply Brief at 13).[64] Bay State contends that NCSC's Financial Planning Department reviews all business cases before approving a budget for an information technology project (Company Brief at 55, citing Exh. BSG/DGC-1, at 48).

3. Analysis and Findings

The CIS is a non-discretionary or non-revenue producing plant investment and must be evaluated under the standard that the investment must be used and useful in providing service to ratepayers and the expenditures must have been prudently incurred. D.T.E. 03-40, at 82 (2003); D.P.U. 85-270, at 20 (1986). Bay State is currently using the CIS for a range of

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[64] The business case is comprised of six sections: Project Description and Fact Sheet; Impact Analysis and Dependancies; Economic Analysis; Risk Analysis; Benefit Justification; Signature Approvals (Exh. BSG/DGC-1, at 48).

necessary operational and informational tasks including meter reading, billing inquiries, payment options, service orders, credit and collection, marketing information, and other information requirements (Exhs. BSG/DGC-1, at 54-55; BSG/DGC-11, at 1). The Company's current CIS went into operation in November of 1999, with additional enhancements installed through 2003 (Exhs. BSG/DGC-1, at 54; BSG/DGC-11, at 1). Accordingly, the Department finds that the CIS is used and useful.

In determining whether Bay State's investment in the CIS is prudent, the Department first examines whether the Company's decision to adopt the CIS itself was reasonable. This determination involves examination of the alternatives Bay State had to the CIS, including the retention of the then-existing customer information system to perform what are acknowledged to be necessary tasks (i.e., customer billing, data storage and retrieval, etc.). A major factor in this analysis involves the extent to which the Company used a cost-benefit analysis or similar management tool to assist in its decision-making process. Finally, we evaluate each phase of the CIS conversion, looking at the progress on the CIS conversion, associated costs, and the cost-control techniques that the Company used. D.T.E. 03-40, at 82; D.P.U. 93-60, at 26-36. Even before D.T.E. 03-40, companies were on notice that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk that the expenditures will be disallowed. D.P.U. 93-60, at 26-36.

In deciding whether to replace its legacy customer information system, Bay State recognized by 1998 that the existing system was 25 years old and not Y2K compliant

(Exh. DTE 16-25; Tr. 15, at 2543; RR-DTE-109). In addition, the Company's then-existing customer information system relied on a computer language and file architecture system that was incompatible with Y2K solutions (RR-DTE-109). Given the need to have a Y2K-compliant customer information system in place no later than December 31, 1999, the Department finds that the Company's decision to replace its customer information system was reasonable.

Having determined that a replacement customer information system was warranted, by mid-1998 the Company decided to apply NIPSCo's system and adapt it to fit the needs of the Company (Exh. DTE 16-24; Tr. 15, at 2528, 2587-2588). At that time, Bay State was seeking Department approval of its acquisition by NiSource.[65] The Department recognizes that, given the potential for economies of scale through a system also used by NIPSCo, an anticipated affiliate, there were reasonable business and economic rationales to favor adopting NIPSCo's customer information system (Exh. DTE 16-24; Tr. 15, at 2545, 2587). Nevertheless, customer benefits must be proved; systematic, contemporaneous documentation of well-analyzed investment decision-making is the best, though not necessarily the only, evidence to sustain such a proof.[66]

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[65] The Company's contract with IBM Global was signed while evidentiary hearings in D.T.E. 98-31 were concluding.

[66] We stress the role of contemporaneous documentation not as a means for future petitioners to "paper the files" with self-serving statements, but because it leaves an analytic trail useful to establishing prudence of conduct or investments. The notion underlies why some statements and records are admissible as credible under judicial rules of evidence. See, e.g., G.L. c. 233, § 78; Fed. R. Evid. 803(6).

Bay State did not contemporaneously confirm that customers would benefit from NIPSCo's customer information system by, for example, putting the CIS project out to bid (Exhs. DTE 16-24; DTE 16-26; Tr. 15, at 2545, 2587). Rather, Bay State selected IBM as the vendor simply because of IBM's familiarity with the software and a sense that IBM would be able to bring the new system on line in a shorter time than otherwise possible (Tr. 15, at 2545, 2587-2588). Maybe IBM would have won a competitive procurement anyway, considering its advantages; but failure to put the matter out to bid at all missed the opportunity to test the waters and put some competitive pressure on IBM. While the Department has not mandated that companies engage in competitive bidding processes, the value and importance of thorough analyses of all major expenditures, including those deemed necessary and non-discretionary, through analytical techniques such as cost-benefit analyses cannot be underestimated. D.P.U. 95-118, at 48-49; D.P.U. 93-60, at 27.[67] A more rigorous application of cost-benefit analysis techniques in the decision-making process associated with the CIS project, providing systematic and contemporaneous documentation of such process, may not have produced a different outcome, but may have alerted the Company to differences between NIPSCo's and Bay State's systems that would have an effect on implementation and data conversion (RR-DTE-109, at 4). Such an analysis would have been the best evidence of the Company's

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[67] The extent to which cost-benefit analysis would be applicable depends on the nature of the plant being considered. For example, in cases involving a gas company's cast-iron main replacements, the decision to embark on the project is not driven by cost-benefit analysis but by the need to maintain system integrity and comply with safety standards (Exh. DTE 16-14). On the other hand, companies have a measure of discretion with other projects, such as information technology applications, in selecting the most cost-effective means of meeting their operational needs. D.T.E. 03-40, at 67.

investment decision-making required to demonstrate the propriety of including the CIS in rate base. The faintest writing can sometimes be more vivid than the clearest memory.

Bay State entered into a contract with IBM in July of 1998 to develop the CIS with a project completion date of August 3, 1999 (RR-AG-75 (Confidential)). The contract estimate included $6,679,520 based on a blended hourly rate for IBM employees, plus an additional 15 to 18 percent for IBM employee travel and living expenses, producing a total IBM employee cost estimate of $7,681,448 (RR-AG-75, at 12 (Confidential)). In addition to direct IBM employee costs, NiSource employees seconded to IBM were to be billed at a rate equal to the actual cost to IBM, plus a markup (id.). A detailed timeline was developed for the various phases of the project, along with a change management process that was established to address any changes in the scope of the project (id. at 10-12, 19-21 (Confidential)). Based on IBM's experience with CIS installations, including its familiarity with NIPSCo's system, the scope of project services to be provided by IBM, and the assumptions relied upon by the parties, the Department concludes that the July 1998 contract estimate of $7.7 million, plus NiSource labor on an as-necessary basis, was reasonable.

In February of 1999, the Company developed a revised capital budget estimate for the CIS project of $8,101,600, consisting of $7,000,000 for the new software upgrades and $1,101,600 for converting data from the legacy customer information system (Exh. DTE 3-26, at 28 (Authorization No. 293030-3003), 36 (Authorization No. 293031-3990); Tr. 15, at 2543; RR-DTE-109, at 4). This estimate included Company payroll costs (Exh. DTE 3-26, at 28 (Authorization No. 293030-3003), 36 (Authorization No. 293031-3990)). In view of the fact

that there is only a difference of about five percent between the July 1998 contract estimate and the February 1999 budget projection, and the later estimate includes NiSource and Bay State payroll and miscellaneous costs, the Department finds that the February 1999 project estimate was reasonable.

During the course of the project, the Company executed 28 change orders with IBM, resulting in additional costs of $3,106,880 (RR-AG-75(B) (Confidential)). Of these, five change orders totaling $686,880 identify specific reasons for the changes (id. at 5-7 (PCR029BS), 17 (PCR016BS), 29 (PCR003BS), 31-34 (BSG PCR001 (Rev. Version A) and PCR001BS)). These include additional customer support requested by the Company (PCR029BS), updated specifications not available earlier when conversion architecture and coding were started (PCR016BS), non-utility operations business functionality testing (BSG PCR001 (Rev. Version A) and PCR001BS) and an extension of project manager time (PCR003BS) (id.). The Department finds that these change orders offer sufficient explanation of the additional work required on the CIS project, in that they cover a range of circumstances that could not have been reasonably known at the time the original CIS project estimate was developed. D.P.U. 93-60, at 33. Therefore, the Department will include these items in the Company's CIS project costs.

The other project change request forms associated with the IBM contract, totaling $2,420,000, generally describe requests for specific additional man-hours (RR-AG-75, at 2-4, 8-16, 18-28, 30 (Confidential)). Under the initial project plan, Bay State employees were to be responsible for testing and training, along with other project activities (RR-DTE-109, at 4).

These personnel either were not available or did not have the capacity given their other workload to perform the task on schedule, however, thus requiring the Company to supplement the labor effort with outside contractors (id.). The Department finds that the Company's ongoing need for specific expertise and the unavailability of in-house personnel justified the expanded use of IBM employees to a greater degree than originally anticipated under the contract. Therefore, the Department will include these items in the Company's CIS project costs.

The CIS was installed in November, 1999, and the project was certified as completed on January 28, 2000 (Exh. BSG/DGC-1, at 54; Tr. 15, at 2528; RR-DTE-113; RR-AG-75(B) at 1 (Confidential)). The total installed cost was $21,546,059, consisting of $15,403,324 for the installed cost of the CIS and an additional $6,142,735 for data conversion (Exhs. BSG/DGC-11, at 1; DTE 3-26, at 29-34, 37-40; DTE 16-25). Bay State represents that the differences from its original cost estimates are the result of numerous factors, including changes in scope, technology, assigned resources, scheduling, and complexity (RR-DTE-109, at 4). The Department recognizes that project cost estimates can vary significantly from actual results, especially when dealing with the complexity of implementing information technology applications. There must be a credible showing, however, that a company made reasonable efforts to contain and manage those costs. D.P.U. 93-60, at 27.

The Company's initial evidence regarding its efforts to control CIS costs is confined to a general description of its capital authorization review policies (Exh. BSG/DGC-1,

at 47-48).[68] During the hearings, Bay State was unable to substantiate the difference between the original $7 million estimate for the CIS software and the final cost of $15.4 million (Tr. 15, at 2545-2546). Moreover, the Company was unable to explain the difference between the original $1.1 million estimate for the data conversion and the final cost of $6.1 million (id. at 2547-2548). Both the Attorney General and the Department attempted to bridge the evidentiary gaps in the record on the Company's CIS project, but with limited success. For example, although the Company was asked for substantiation of the various enhancements made to the CIS, its response was limited to a recitation of general hourly manpower charges (id. at 2582-2584; Exh. DTE 16-23; RR-DTE-112). More significantly, the Company was unable to provide supporting documentation for the actual costs associated with the CIS project (id. at 2567-2568; RR-DTE-109).[69] Although Bay State points to the META Study as evidence of the cost-effectiveness of its CIS project, this study was not even contracted for until November of 2004 (Exh. AG 3-16(a)). Therefore, the META Study does not offer the systematic, contemporaneous documentation of well-analyzed investment decision-making sought by the Department.[70] Although the Company's witnesses were afforded the opportunity

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68 This lack of substantiation is in marked contrast to the Company's presentation of its other non-discretionary plant additions, where reasons for cost overruns were provided in considerable detail (Exhs. BSG/DGC-8; DTE 3-21 (Rev.); DTE 3-32; AG 1-19).

69 Bay State's Lawson General Ledger report system only retains account period balances for the years prior to 2000 (RR-DTE-109).

70 We do not say that after-the-fact analyses, proffered by a proponent of cost-recovery or rate base addition, necessarily lacks credibility; but they do lack the immediacy and force of contemporaneously prepared documentation of decisions and thus are more prone to skepticism and impeachment.

to offer written responses on redirect examination, Bay State did not cure the deficiencies of its presentation on the CIS project.[71] The silence is telling.

Although Bay State points to its various review policies and business case analyses for major capital projects (Exh. DTE 16-11), the Company fails to demonstrate either that it had applied these policies at all, or that it applied them in a reasonable manner. The Department finds that Bay State's actions with respect to the CIS conversion project were lacking in key areas, through its failure to: (1) fully consider alternative courses of action; (2) apply cost-enefit management techniques to the CIS project; and (3) exercise adequate cost controls. Therefore, the Department can only include, in the Company's rate base associated with the CIS software, the original project cost estimate of $7,000,000, along with $3,106,880 in those project change requests that provide acceptable explanations for the additional work required on the CIS project (Exh. DTE 3-26, at 28, 36; RR-AG-75(B) (Confidential) at 6-7, 17, 31-34). The Department will also include the original database conversion estimate of $1,101,600, for a total allowable CIS project cost of $11,208,480. While at least some portion of the remaining CIS costs may have a reasonable basis, the Company has not made this showing on the record. The burden of proof lay with Bay State as proponent of recovery: that burden was not sustained for these items, and so disallowance follows in consequence. Accordingly, the

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[71] Specifically, Bay State only addressed: (1) the Company's information technology capital authorization process; (2) the selection of NIPSCo's system as the basis for the CIS; (3) a description of various CIS enhancements listed in Exhibit DTE 16-23; (4) the climate of client-server migration; (5) a description of a project listed in Exhibit DTE 3-21; and (6) the types of cost-benefit analysis done for information technology that would not be documented in the traditional sense (Tr. 15, at 2589-2592). It did not address reasons for the cost overruns.

Department will exclude the remaining $10,337,579 from rate base, representing $5,296,444 in CIS software costs and $5,041,135 in CIS Pro-Edits conversion costs.

In recognition of the Department's decision to exclude $10,337,579 in CIS-related expenses from Bay State's rate base, a corresponding reduction to the Company's amortization reserve is appropriate. D.T.E. 03-40, at 88; Boston Gas Company, D.P.U. 93-60-A at 7-8 (1993).[72] The Company begins to amortize its information technology assets once they are placed into service (Tr. 15, at 2566). The CIS was first placed into service in November of 1999, and the CIS Pro-Edits went into service during 2000 and 2001 (Exh. BSG/DGC-1, at 54; RR-DTE-108). Both use a ten-year amortization period (RR-DTE-108).

In order to determine the accumulated amortization associated with the disallowed portion of the CIS, the Department will first divide the 62 months covering the period from November 1999 through December 2004 into the ten percent annual amortization, and multiply the resulting 50.83 percent amortization factor by the disallowed CIS software investment of $5,296,444. This produces an accumulated amortization associated with the disallowed portion of the CIS of $2,692,359. To determine the accumulated amortization associated with the disallowed CIS Pro-Edits, the Department will divide the 48 months covering the period from January 2001 through December 2004 into the ten percent annual amortization, and multiply the resulting 40.0 percent amortization factor by the disallowed CIS Pro-Edits

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[72] Although the Company asserts that the net rate base associated with the CIS is $11,182,919, the source of the Company's number is unclear. Therefore, the Department has calculated the required amortization reserve adjustments based on the in-service dates of the CIS investments and their ten-year amortization periods.

investment of $5,041,135.[73] This produces an accumulated amortization associated with the disallowed portion of the CIS Pro-Edits of $2,016,454.

Accordingly, Bay State's reserve for amortization associated with the CIS project will be reduced by $4,708,813, producing a net reduction of $5,628,766. The Department will also reduce the Company's deferred income tax reserve by $2,207,883, representing the $5,628,766 in disallowed unamortized CIS project costs multiplied by the combined tax rate of 39.225 percent.[74]

C. Cash Working Capital Allowance

1. Introduction

In their day-to-day operations, utilities require funds to pay for expenses incurred in the course of business, including operating and maintenance ("O&M") expenses. These funds are either generated internally by a company or through short-term borrowing. Department policy permits a company to be reimbursed for costs associated with the use of its funds for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase 1) at 26, citing Western Massachusetts Electric Company, D.P.U. 87-260, at 22-23 (1988). This reimbursement is accomplished by adding a working capital component to the rate base computation.

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[73] The CIS Pro-Edit investments appear to have been placed on line at various times during 2000 and 2001; the Department considers a January 2001 starting period to represent a reasonable method of determining the appropriate adjustment to Bay State's reserve for ratemaking purposes.

[74] A corresponding reduction to the Company's amortization expense of $1,033,758 is also required, as provided in Schedule 3 of this Order.

Non-fuel working capital needs have been determined through either the use of a lead-lag study or a 45-day O&M expense allowance. D.T.E. 03-40, at 92. In the absence of a lead-lag study, the Department has generally relied on the 45-day convention as reasonably representative of O&M working capital requirements. D.P.U. 88-67 (Phase 1) at 32-33. However, the Department has expressed concern that the 45-day convention first developed in the early part of the 20th century no longer provides a reliable measure of a utility's working capital requirement. D.T.E. 03-40, at 92; Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 15 (1998). Therefore, the Department requires each gas and electric distribution company to either (1) conduct a lead-lag study where cost-effective, or (2) propose a reasonable alternative to a lead-lag study to develop a different interval.[75] D.T.E. 03-40, at 92; Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 57 (2002).

Bay State conducted a lead-lag study for the instant case, using in-house staff, to update the net lag days associated with purchased gas working capital and to establish the net lag days to be used for other O&M expense working capital that will be included in base rates (Exh. BSG/JES-2). The study resulted in a purchased gas net lag of 25.30 days or 6.932 percent (25.30/365) (id.). This was based on a revenue lag of 62.83 days and a purchased gas lead of 37.34 days (id. at 1). Regarding the other O&M working capital, the Company concluded that the lag between revenues and expenses was 42.21 days (id.). This

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[75] In this context, "cost-effective" means that the normalized cost of the study (i.e., the cost of the study divided by the normalization period used in the utility's rate case) is less than the reduction in revenue requirements that would occur using the results of the lead-lag study in lieu of the 45-day convention. D.T.E. 02-24/25, at 57 n.34.

was based on a revenue lag of 62.83 days and an expense lag of 20.62 days (id.). A cash working capital factor of 11.564 percent was derived by dividing the net lag days by 365 days (id.). This factor, multiplied by Bay State's pro forma O&M expense of $98,983,216 produces a cash working capital expense of $11,446,419. No other party commented on this issue.

2. Analysis and Findings

If properly designed, lead-lag studies are an appropriate method to determine cash working capital. However, lead-lag studies are complex and costly to undertake. Not wanting to require expensive lead-lag studies, the Department has encouraged utilities to consider and offer other cost-effective methods to produce lower working capital requirements than the traditional 45-day convention. D.T.E. 03-40, at 92 (2003); D.T.E. 02-24/25, at 55; D.T.E. 98-51, at 15.

In the present case, Bay State conducted a lead-lag study using NCSC regulatory support personnel at a total estimated cost of between $8,000 and $12,000 (Exh. DTE 23-2). The Company has proposed to apply the results of this study to meet its cash working capital needs, through a purchased gas net lag factor of 25.30 days and a composite 42.21-day cash working capital factor. When we compare the de minimis normalized cost of preparing the lead-lag study to the effect the lower cash working capital factor has on revenue requirements,

we conclude that the Company's decision to perform a lead-lag study was a cost-effective means to determine its working capital needs.[76]

The Department has examined Bay State's lead-lag study, and finds that the study produces a reliable measure of the Company's purchased gas and O&M working capital requirement. Accordingly, the Department shall apply a 42.21-day cash working capital requirement to the level of Company O&M expense included as part of this Order. The effect of this cash working capital factor on the Company's revenue requirement is provided in Schedule 6 of this Order. The purchased gas net lag of 25.30 days is to be used by Bay State in calculating its purchased gas working capital recovered via the CGAC.

D. Completed Construction in Service

1. Introduction

As of the end of the test year, Bay State reported a construction work in progress ("CWIP") balance of $7,385,734 (Exh. AG 1-2 (2004 Annual Return at 13)). Of this amount, the Company includes $1,053,621 in rate base, representing 19 non-revenue producing plant additions that the Company states had been completed during the test year, but had not yet been transferred to respective plant accounts (Exhs. BSG/JES-1, at 49; BSG/JES-1, Workpaper JES-7, at 2; BSG/JES-1, Sch. JES-13, at 4; Tr. 5, at 919).

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[76] Based on the Company's test year O&M expense of approximately $99 million, a one-day decrease in the lead-lag factor produces an annual reduction of approximately $271,000 to cash working capital requirements, which translates into a decreased revenue requirement of approximately $36,000.

2. Positions of the Parties

a. Attorney General

The Attorney General challenges the Company's claim that $1,053,621 of non-revenue producing plant costs included in CWIP were, in fact, completed during the test year (Attorney General Brief at 48-49). In support of his position, the Attorney General points out that the Uniform System of Accounts for Gas Companies ("USOA-Gas Companies") specifies that this type of plant is to be booked to Account 106, Completed Construction not Classified (id., citing USOA-Gas Companies at 33 (Balance Sheet Accounts, Account 106)).[77] Although the Attorney General acknowledges that plant booked to Account 106 may be eligible for inclusion in rate base, the Company's 2004 Annual Return to the Department reports a zero balance for this account as of the end of the test year (id. at 49-50, citing 2004 Annual Return at 13). The Attorney General maintains that, because the annual returns to the Department are submitted under the penalties of perjury, the information contained in the annual return must be considered as true, thus rebutting the Company's claim that the Company's CWIP balance includes any completed plant (id., at 50). The Attorney General contends that absent of any evidence to support the Company's claims, no plant in service numbers presented in this case should be relied upon until an independent auditor can verify the balances (Attorney General Reply Brief at 21).

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[77] Account 106 includes the balance of work orders for utility plant which has been completed and placed in service, but not yet classified for transfer to detailed utility plant accounts. 220 C.M.R. §§ 50.00 et seq.

b. Company

The Company argues that the Attorney General's proposed rate base disallowance is inappropriate and does not recognize the benefits that accrue to ratepayers through plant in service at the end of the test year (Company Brief at 59). The Company maintains that finished plant should be included in rate base, whether or not the accounting entries have been made to transfer the plant from CWIP to plant in service (id.). Moreover, the Company notes that the Attorney General's reliance on the reported balance in Account 106 is misplaced, because the Company has not recorded entries in Account 106 since the end of 1992 (id., citing Exhs. AG 1-2; DTE 16-2). The Company considers the Attorney General's suggestion as contrary to the evidence in the record and resulting in an arbitrary basis for the disallowance of plant in service but not yet booked to plant in service accounts (id., citing Exh. DTE 16-3).

3. Analysis and Findings

For costs to be included in rate base, the expenditures must be prudently incurred and the resulting plant must be used and useful in providing service to ratepayers. D.P.U. 85-270, at 20. The Department has historically not allowed the inclusion of CWIP in rate base, because unfinished construction cannot provide any service to then-present ratepayers. Oxford Water Company, D.P.U. 1219, at 4 (1983); D.P.U. 906, at 208.

The Attorney General questions whether the non-revenue producing plant additions included in rate base by the Company were used and useful, i.e., whether they were completed and in service. While the Attorney General cites Bay State's 2004 Annual Return as contradicting the Company's claims, the USOA-Gas Companies does not dictate ratemaking

treatment. The accounting systems prescribed by the Department, including the USOA-Gas Companies codified as 220 C.M.R. §§ 50.00 et seq., represent systems whereby costs are sorted and categorized to provide the Department with information on utility operations and aid in the review of utility costs; they do not establish either the reasonableness per se of the reported costs or the ratemaking treatment to be accorded such costs. D.T.E. 03-40, at 208; Boston Edison Company, D.P.U./D.T.E. 97-95, at 77 (2001). The Department considers the in-service status of the additions in question as unaffected by whether the Company has made the appropriate accounting entries to transfer the cost of these projects from CWIP to plant in service accounts.[78] The plant items in question were completed and placed into service between October and December of 2004 (Exhs. BSG/JES-1, Workpaper JES-7, at 2; DTE 16-2; Tr. 5, at 918). Therefore, the Department will include the plant additions of $1,053,621 in rate base. Consistent with this ratemaking treatment, the Department finds it appropriate to reduce the Company's proposed plant additions by $106,205 to recognize fully completed retirements that have not yet been closed out to plant accounts (Tr. 5, at 865-869;

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[78] Bay State admittedly has not booked entries to Account 106 since 1992. The fact that some plant booked to CWIP as the end of a given year may have more appropriately been booked to Account 106 is not intuitive from a review of the Company's annual returns for the years 1992 through 2004. The Company's failure to maintain its books consistent with the USOA-Gas Companies resulted in time and resources being unnecessarily spent on this matter by the parties and the Department, and heightened the risk that Bay State's completed construction would have been excluded from rate base. The Company is directed to resume using Account 106 to book completed construction not yet classified, as required by the USOA-Gas Companies.

RR-DTE-36).[79] Accordingly, the Company's proposed rate base shall be reduced by $106,205.

V. OPERATING EXPENSES

A. Payroll Expense

1. Introduction

During the test year, Bay State incurred $27,536,324 in union payroll expense and $5,718,664 in non-union payroll expense, for a total payroll expense of $33,254,988 (Exh. BSG/JES-1, Sch. JES-6, at 2). The Company proposes to increase its test year union payroll expense by $1,246,031[80] and to increase its test year non-union payroll expense by $443,840, for a total payroll adjustment of $1,689,871 (Exhs. BSG/JES-1, at 14; BSG/JES-1, Sch. JES-6, at 2; RR-DTE-1; RR-DTE-18).

The Company's proposed union payroll increase consists of obligations the Company has for annual merit payroll increases as of March 1 of each year (Exh. BSG/JES-1, at 13). Therefore, the payroll adjustment includes the annualization of the 2004 salary increases and the full March 1, 2005 merit increase (id.). The Company's proposed non-union payroll increase consists of obligations the Company holds for a merit increase of two percent confirmed for March 1, 2006 (id. at 13-14).

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[79] This adjustment also requires a concordant reduction to depreciation expense, as noted in Section V.U.3 of this Order.

[80] The Company's union payroll expense has been increased to account for changes due to the signing of a new Lawrence Local 326 union contract (which adds an additional $57,157 in 2005 straight time labor and $12,456 in 2005 in overtime labor to the contract) (RR-DTE-18).

In support of the Company's total payroll increase, Bay State provided comparative analysis that examine compensation and benefits expense levels relative to other investor owned utilities in New England, and in the Northeast, and to companies in other market areas where Bay State and NCSC compete for similarly-skilled employees (Exh. BSG/SAB-1, at 22). This comparative analysis relied on a variety of industry surveys including the following: the American Gas Association salary survey for 2003; the Mercer Metropolitan Benchmark salary survey; the 2004/2005 US Compensation Planning Survey by Mercer Human Resource Consulting; the Salary Budget Survey for 2004/2005 by WorldatWork; and the U.S. Salary Increase Survey for 2004 and 2005 by Hewitt (id. at 23-34).

2. Company's Position

Bay State represents that its payroll adjustments apply known payroll increases granted during 2005 and that will be granted through the middle of 2006 (Company Brief at 71). The Company states that the appropriate union payroll increase is $1,243,031, representing the Company's six separate collective bargaining agreements covering its union employees, including a contract with Lawrence Local 326 that was negotiated during the rate proceeding (id. at 71-72, citing Exhs. BSG/JES-1, at 13; BSG/JES-1, Sch. JES-6, at 2). Bay State asserts that the reasonableness of its proposed union payroll expense was confirmed by a number of comparative analyses (id. at 72, citing Exhs. BSG/SHB-1, at 8-10; BSG/SHB-1, Schs. SHB-1, SHB-9). No party contested the Company's payroll adjustment for union employees.

Turning to the Company's non-union payroll expense, Bay State contends that it has an annual merit payroll increase obligation scheduled for March 1 of each year (Company Brief

at 73; Exh. BSG/JES-1, at 13). The Company argues that the reasonableness of its non-union payroll adjustment was confirmed by a number of comparative analyses (Company Brief at 73, citing Exh. BSG/SHB-1). No party contested the Company's payroll adjustment for non-union employees.

Concerning Bay State's incentive compensation program, the Company states that in 2004 the Company booked payroll accrual to match the incentive payments made to employees for 2003 performance and, therefore, an adjustment was needed to remove the under-accrual from the test year (Company Brief at 74, citing Exh. BSG/JES-1, at 15). The Company states that the revenue requirement includes only the accrued payroll expense for 2004 at the first "trigger" level of the incentive compensation program (id. at 74, citing Exh. BSG/JES-1, at 15-16). The Company asserts that it has demonstrated the reasonableness of its incentive compensation program, as well as demonstrated that the plan is appropriately designed to incent good employee performance for the benefit of ratepayers (id., citing Exhs. BSG/SAB-1, at 19-21; BSG/JES-1, at 15-16).

3. Analysis and Findings

The Department's standard for union payroll adjustments requires that three conditions be met: (1) the proposed increase must take effect before the midpoint of the first twelve months after the rate increase; (2) the proposed increase must be known and measurable, i.e., based on signed contracts between the union and the company; and (3) the company must demonstrate that the proposed increase is reasonable. D.P.U. 96-50 (Phase I) at 43;

Massachusetts Electric Company, D.P.U. 95-40, at 20 (1995); Cambridge Electric Light Company, D.P.U. 92-250, at 35 (1992).

To recover an increase in non-union wages, a company must demonstrate that: (1) there is an express commitment by management to grant the increase; (2) there is an historical correlation between union and non-union raises; and (3) the non-union increase is reasonable. D.P.U. 96-50 (Phase I) at 42; D.P.U. 95-40, at 21; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 14 (1983). In addition, non-union salary increases that are scheduled to become effective no later that six months after the date of the Order may be included in rates. Boston Edison Company, D.P.U. 85-266-A/271-A at 107 (1986).

In determining the reasonableness of a company's employee compensation expense, the Department reviews the company's overall employee compensation expense to ensure that its employee compensation decisions result in a minimization of unit-labor costs. D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 55. This approach ensures and recognizes that the different components (e.g., wages and benefits) are to some extent substitutes for each other, and that different combinations of these components may be used to attract and retain employees. The Department also requires companies to demonstrate that they have minimized their total unit-labor cost in a manner that is supported by their overall business strategies. D.P.U. 92-250, at 55. However, the individual components of a company's employment compensation package are appropriately left to the discretion of a company's management. Id.

To enable the Department to assess the reasonableness of a company's total employee compensation expense, companies are required to provide comparative analyses of their

employee compensation expenses. D.P.U. 96-50 (Phase I) at 47. Both current and total compensation expense levels and proposed increases should be examined in relation to other New England investor-owned utilities and to companies in a utility's service territory that compete for similarly-skilled employees. D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 56; D.P.U. 92-111, at 102-103 (1992); Massachusetts Electric Company, D.P.U. 92-78, at 25-26.

With respect to the Company's union payroll increases, the proposed adjustments appropriately include only those increases that have been granted or will be granted before the midpoint of the first twelve months after the Department's Order in this proceeding (i.e., May 1, 2006) (Exh. BSG/JES-1, at 13-14). Because the union payroll increases are based on signed collective bargaining agreements, the Department finds that these proposed increases are known and measurable (id.).

To address the requirement that there be an historical correlation between union and non-union wages, the Department evaluates the relationship between union and non-union increases. The Berkshire Gas Company, D.T.E. 01-56, at 56; D.P.U. 96-50 (Phase I) at 42. Annual union wage increases granted between 1995 and 2005 have ranged between 2.30 percent and 4.00 percent (Exh. BSG/SAB-1, Sch. SAB-4). For the same time period, annual non-union salary increases have also generally ranged between 2.30 percent and 4.00 percent[81] (id.). Based on this evidence, the Department finds that a sufficient correlation exists between

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[81] In 2002, the Company did not give a merit percentage increase to its non-union exempt employees (Exh. BSG/SAB-1, Sch. SAB-4).

union and non-union wage increases. See Essex County Gas Company, D.P.U. 87-59-A at 18 (1988).

Finally, Bay State provided survey results that indicate that the hourly rates paid to the Company's union employees are comparable to the hourly average rates of other gas and electric utilities in the Northeast (Exh. BSG/SAB-1, Sch. SAB-1). Department precedent requires the Company to demonstrate that proposed union wage increases are reasonable. The union survey results demonstrate that the Company's union hourly wages are reasonable compared to other gas and electric utilities in the Northeast (id.). In addition, Bay State Gas provided comparisons of contractual wage increases by percentage between itself, and other utility companies in the Northeast region and the nation as a whole (Exh. BSG/SAB-1, Sch. SAB-7). This analysis also demonstrates that the Company's proposed union wage increases are reasonable. Having found that the proposed union wage increases (1) take effect before the midpoint of the twelve months after the rate increase, (2) are known and measurable, and (3) are reasonable, the Department will allow the Company to adjust its test year cost of service for the union payroll increases.

With respect to the Company's non-union payroll increases, the proposed adjustments appropriately include only those increases that have been granted or will be granted before the midpoint of the first twelve months after the Department's Order in this proceeding (Exh. BSG/JES-1, at 13-14). Because management has expressly committed to granting another non-union payroll increase on March 1, 2006, the Department finds that this proposed increase is known and measurable (id.).

In support of the historical correlation between union and non-union raises, Bay State provided a comparative analysis of union and non-union wage increases between 1995 and 2005 (Exh. BSG/SAB-1, Sch. SAB-4). This analysis demonstrates that union and non-union wage increases have been very closely tied between 1995 and 2005. Therefore, the Department finds that there is a sufficient historical correlation between union and non-union wage increases.

To demonstrate the reasonableness of the non-union wage increase, Bay State provided the results of an American Gas Association survey, which compared actual salaries for Bay State and NiSource to those for Northeast gas companies for a variety of job categories (Exh. BSG/SAB-1, Sch. SAB-6). This comparison shows that the Company's average total cash compensation level is 4.4 percent below the Northeast's total cash compensation for utility companies, and 0.3 percent below the Midwest's total cash compensation for utility companies (id.). The Company also provided a comparison of Bay State's actual salaries to general industry salaries within the greater metropolitan Bay State area for a variety of job categories, which shows that the Company's annual base salary is only slightly higher than that for all industries in Boston, which, while being reasonable, allows the Company to attract, retain, and motivate qualified employees (Exh. BSG/SAB-1, Sch. SAB-5). Therefore, the Department finds that the amount of the non-union payroll increase is reasonable.

Having found above that the proposed non-union wage increases (1) are known and measurable, (2) indicate an historical correlation between union and non-union wage increases, and (3) are reasonable, the Department will allow the Company's proposed adjustment to its

test year cost of service for the non-union payroll increases. The total union and non-union payroll adjustments increase test year payroll expense by $1,680,387 (Exhs. BSG/JES-1, at 14; BSG/JES-1, Sch. JES-6, at 2 [Rev. 1]; RR-DTE-1; RR-DTE-18).

B. Executive Compensation of NiSource Executives

1. Introduction

In 2001, Bay State was allocated approximately $70,000 of the compensation provided to NiSource's most highly compensated executives (Exh. UWUA 2-11(b)). Also in 2001, Bay State was allocated 0.05 percent of the compensation provided to two NiSource executives, 5.5 percent of another executive's compensation, and just under ten percent of another executive's compensation (id.).

In 2002, the Company was allocated between 3.85 percent and 11.59 percent of the cost for executive compensation for the five most highly compensated NiSource executives, and the Company also was allocated small portions of several other NiSource executives' compensation, for a total cost of approximately $900,000 (Exh. UWUA 2-11(b)). By 2004, the Company was allocating costs relating to 13 of the 20 most highly-compensated NiSource executives, at a cost of almost $1.15 million (Exh. UWUA 2-11(d)).

2. Positions of the Parties

a. Local 273

Local 273 states that the amount of NiSource executive compensation being allocated to Bay State is excessive (UWUA Brief at 64). Local 273 asserts that this amount is more than double the total compensation awarded to all of the highly-compensated Bay State executives

who are actually based in Massachusetts (id.). Local 273 asserts that there is no evidence as to the reasonableness of the compensation packages of NiSource executives whose costs are allocated to Bay State (UWUA Reply Brief at 11). Local 273 asserts that given the lack of evidence supporting the reasonableness of the very large compensation provided to NiSource's highly-compensated executives, and that the amounts allocated to Bay State have risen exponentially from approximately $70,000 in 2001 to over $1 million in the test year, the Department should disallow 50 percent of the executive compensation included in the test year cost of service (UWUA Brief at 64-65).

b. Company

Bay State asserts that the reasonableness of the allocated cost for executive compensation has been confirmed by the allocation formulas approved by the Securities and Exchange Commission ("SEC") (Company Reply Brief at 32). The Company states further that these compensation levels are compared by NiSource to executive compensation levels in the marketplace on a continuing basis and that all NiSource employees, including its executives, are paid at the levels required to attract and retain competent and skilled talent (id., citing Exh. BSG/SAB-1). The Company further contends that the UWUA's proposed arbitrary 50 percent reduction in allocated charges for executive compensation has no rationale or support (id.).

3. Analysis and Findings

Under Department precedent, in order to qualify for inclusion in rates, payments made by a utility to an affiliate must be: (1) for activities that specifically benefit the regulated

utility and do not duplicate services already provided by the utility; (2) made at a competitive and reasonable price; and (3) be allocated to the utility by a formula that is both cost-effective and non-discriminatory for services specifically provided to the utility by the affiliate and for general services which may be allocated by the affiliate to all operating affiliates. D.T.E. 02-24/25, at 180; Hingham Water Company, D.P.U. 88-170, at 21-22 (1989); AT&T Communications of New England, Inc., D.P.U. 85-137, at 51-52 (1985). The level of all affiliate charges must also be justified and be reasonable with proper substantiation. D.T.E. 02-24/25, at 181-182. Bay State has provided evidence that the executive compensation allocated to Bay State specifically benefit the regulated utility and does not duplicate services already provided through a description of NCSC's billing procedures (Exh. BSG/JES-1, at 28-30). Specifically, "allocations among affiliates are made only if it is impractical to charge an affiliate directly" (id. at 29). For example, allocations are made through "convenience billing," which include payroll funding, employee benefits, premiums and leasing, that reflect services routinely provided on behalf of all affiliates (id.). All direct and allocated costs are invoiced monthly. Further, NiSource's human resource consultant, Hewitt Associates ("Hewitt"), conducted an independent review of NiSource's executive compensation structure, and found it to be reasonable (Exh. BSG/SAB-1, at 3-6). Finally, NCSC assigns the cost for these services to Bay State pursuant to SEC-approved allocators and follows the SEC Uniform System of Accounts for Service Companies and Subsidiary Companies, without any mark-up (Exh. BSG/JES-1, at 28). For these reasons, the Department finds that the Company's allocation of executive compensation cost to Bay State meets the

Department's precedent (Exh. BSG/JES-1, at 29-30). Further, the UWUA's proposal of a 50 percent reduction in executive compensation allocated to Bay State is arbitrary and not supported by any record evidence. Therefore, we reject the UWUA's proposal to reduce the test year level for executive compensation cost by 50 percent.

C. Pension/Post Retirement Benefits Other Than Pension

1. Introduction

During the test year, the Company booked $3,182,669 in pension expense and $2,447,613 in post-retirement benefits other than pensions ("PBOP") expense (Exh. BSG/SAB-1, at 45). Bay State currently recovers its pension and PBOP obligations through base rates. The Company proposes to recover all of its pension and PBOP expenses through a reconciling mechanism that it claims is similar to others approved by the Department (id. at 46, citing Fitchburg Gas and Electric Light Company, D.T.E. 04-48 (2004); Commonwealth Electric Company/Cambridge Electric Light Company/Commonwealth Gas Company/Boston Edison Company, D.T.E. 03-47-A (2003); D.T.E. 03-40).

To implement this mechanism, Bay State requests that the Department first grant it authority to recognize a regulatory asset for the amount of its current additional minimum liability ("AML") and to adjust the regulatory asset for any future changes to the AML (Exh. BSG/SAB-1, at 50-51). An AML is equal to any underfunding in a company's pension plan plus any prepaid pension balances (Exh. DTE 1-11). The offset to the AML is an intangible asset and an accumulated charge to shareholders' equity (Exh. BSG/SAB-1, at 50). During the test year, the Company recorded its then existing AML of $26,825,928 on its

financial statements in accordance with the requirements of Statement of Financial Accounting Standards "SFAS" No. 87 (id.). The offset to the AML was the recognition of an intangible asset of $7,514,027 and a charge to shareholders' equity of $19,311,901 (id.).[82] The AML resulted from lower than expected returns on pension plan assets during the years 2001 to 2003 (id.). The Company states that the Department's approval to establish a regulatory asset for the AML would allow Bay State to reverse the cumulative charges to stockholders' equity recorded on its books at the end of the test year. The Company states that the reconciling mechanism is then necessary to demonstrate that the regulatory asset established for the AML is "probable of recovery," pursuant to the requirements of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (id.).

Under the Company's proposal, after the creation of a regulatory asset for the AML, an annual reconciling mechanism ("Pension and PBOP Mechanism" or "PAM") would be established for the identified pension and PBOP expenses (id, at 48). Any differences between pension and PBOP expenses calculated in accordance with SFAS No. 87 and SFAS No. 106 and those amounts included in rates would be deferred and recognized as a regulatory asset or liability in accordance with SFAS No. 71 (id.).[83] Amounts recorded as a regulatory asset or

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82 The Company initially recorded the AML in 2002 (RR-DTE-53). By the end of the test year, the AML amounted to $25,153,000 with an offsetting intangible asset of $6,765,000, resulting in an accumulated charge to equity of $18,388,000 (id.). Additional entries were recorded in November of 2003 and November of 2004 (id.).

83 Pension expense is determined in accordance with SFAS No. 87, "Employers' Accounting for Pensions." PBOP expense is calculated in accordance with SFAS No. 106, "Employers' Accounting for Post-retirement Benefits Other Than

(continued…)

liability would be collected from or returned to customers as part of the Company's LDAC. In addition, Bay State seeks to recover carrying charges on its prepaid pension and PBOP balances, at the pre-tax weighted cost of capital determined in this proceeding (Exhs. DTE 1-17; BSG/JAF-1, Sch. JAF 3-1, Tariff M.D.T.E. No. 37, §§ 501-504). The Company proposes to file the PAM annual adjustment factor for the upcoming year with each peak period LDAC filing, to take effect on November 1 of that year (Exh. BSG/JAF-1, Sch. JAF 3-1, Tariff M.D.T.E. No. 37, § 505).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject the Company's reconciling mechanism because the PAM formula is not objective (Attorney General Brief at 28). According to the Attorney General, the PAM formula contains complicated variables that contain a considerable degree of subjectivity in their calculation (id. at 28-29). The Attorney General reasons that, because of the degree of subjectivity inherent in the formula, pension and PBOP obligations are not the type of objective, actual cost pass-through provision operating in terms of a mathematical formula recognized by the Supreme Judicial Court (id. at 29, citing Consumers Org. Fair Energy Equity v. Dept. Of Pub. Util., 368 Mass. 599, 602 (1975)). Moreover, the Attorney General notes that the proposed PAM tariff does not require the Company to deposit all the funds collected through the pension/PBOP mechanism into the

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[83] (…continued)
Pensions" (Exh. BSG/SAB-1, at 47).

respective trust funds, thereby allowing the Company to use the funds for any purpose, including enriching shareholders (id.). According to the Attorney General, this lack of dedication of funds to the respective trusts, combined with the high degree of subjectivity in calculating the tariff formula variables, renders the tariff defective and provides no way to determine whether the increases in rates resulting from its ongoing operation will be just and reasonable (id. at 29-30). Therefore, the Attorney General concludes that the Department should reject the proposed PAM (id. at 30). In the alternative, the Attorney General urges that, if the pension adjustment mechanism is approved, the Department continue its practice of allowing discovery, hearings and briefs to investigate each annual compliance filing (id. at 28).

b. Company

Bay State notes that the Department has determined that a pension and PBOP reconciling mechanism is appropriate if a company establishes: (1) the magnitude and volatility of pension and PBOP expense; (2) that this volatility results from accounting requirements and other external factors, rather than the actions of the company; and (3) that a reconciling mechanism is an effective way to avoid the negative financial effects of pension and PBOP volatility (Company Brief at 76, citing D.T.E. 04-48, at 19). The Company points out that the volatility in these expenses is due to the performance of the capital markets and fluctuations in long-term interest rates, factors not within the control of the Company (Company Brief at 76). The Company argues that, although these expenses have stabilized over the past three years, there have been large variations in pension and PBOP expenses over the most recent five-year period caused by variations in asset returns and interest and discount

rates (id. at 77). In the Company's view, pensions and PBOP expenses are a "long-term proposition" and two or three years of relatively stable performance is not indicative of future results (id., citing Exh. DTE 8-9; Tr. 8, at 1315-1316).

The Company disputes the Attorney General's claim that the proposed pension and PBOP mechanism should be rejected because the tariff formula is not objective (Company Brief at 79). The Company maintains that the pension and PBOP expenses to be recovered through the tariff formula are subject to the requirements of SFAS No. 87 and No. 106, as well as review by the Company's accountants and actuaries (id.). Therefore, according to the Company, there should be no concern about the calculation of pension and PBOP expenses (id.).

In a like manner, the Company disagrees with the Attorney General's position that the proposed tariff formula does not require the Company to deposit funds collected through the tariff into the respective benefit trust funds (id.). The Company notes that deposits into the PBOP trusts are based upon tax deductible contributions allowable for a particular funding period and reasonable business judgment (id.). For pensions, the Company points out that it funds its pension plan to meet the minimum contribution amount required by law and that any additional contributions are made based upon contribution amounts allowable for a particular funding period and reasonable business judgment (id. at 79-80).

In response to the Attorney General's claim that the PAM tariff formula provides no way to judge the reasonableness of the rates collected, the Company urges the Department to continue the practice of permitting investigation by all parties of its annual compliance filings,

as suggested by the Attorney General, as a means of ensuring that rates are just and reasonable (id. at 80).

3. Analysis and Findings

a. Introduction

In D.T.E. 03-47-A at 2-8, the Department reviewed at length the progressive difficulty in recent decades of "determin[ing] representative levels of pension and PBOP expenses for inclusion in base rates and, further, [of settling] on a base-rate treatment method applicable both to all regulated companies and to all circumstances that may reasonably be expected to arise between rate cases." Id. at 6. The Department noted that its own treatment of these expenses had sometimes shifted course as a result of this difficulty. The Department then took the occasion of the petition before it in D.T.E. 03-47 to effect a long-term "resolution" of the matter. Id. at 2, 6. "Economic events now persuade us to consider whether and how to develop a *consistent* practice and treatment of these expenses *henceforth, for all* jurisdictional gas and electric companies." Id. at 6 (emphasis added). D.T.E. 03-47-A set out to provide "a long-term solution to the Department's chronic dilemma of setting a representative level for pension costs and resolving the incongruity amongst Financial Accounting Standards Board ("FASB") standards, Employee Retirement Income Security Act/Internal Revenue Services ("ERISA/IRS"), and regulatory ratemaking," particularly in view of the prospect that failure to resolve that "incongruity" threatened that "the problem would recrudesce." Id. at 28. D.T.E. 03-47-A viewed "the relief sought [a]s an opportunity to resolve the vexed question of pension expense recovery" described at length in Section III of that order. Id. at 2-8, 44. The

solution may have arisen from immediate and exigent circumstances, but it answered a long-standing, industry-wide need in a generally applicable way.

The Department immediately applied the D.T.E. 03-47-A solution in D.T.E. 03-40, at 306-314. We noted that, especially in the context of a ten-year PBR term, Boston Gas and its customers might "be subject to potentially harmful financial consequences, stemming from potential SFAS 71 write-offs." Id. at 307-308. Boston Gas would not have had the G.L. c. 164, § 94 rate filing remedy readily at hand during the ten-year, performance-based rate term, an alternative remedy discussed in D.T.E. 03-47-A at 41, 45. Granting Bay State's request for a PAM is consistent with the general resolution of pension/PBOP expense recovery first fashioned in D.T.E. 03-47-A and then applied in D.T.E. 03-40. As a result, we grant the petition on the basis set forth below. In so doing, we take the opportunity presented to reduce the financial and operational risks - whether latent, as here, or exigent, as in D.T.E. 03-47-A - that arise from the intersecting, but not always fully compatible, demands of FASB rules, federal Internal Revenue Service ("IRS") and Employee Retirement Insurance Security Act ("ERISA") pension law, and prior Department rate practice.

b. Creation of Regulatory Asset

Bay State requests that the Department allow it to record a regulatory asset for its current AML, with authority to adjust the regulatory asset for any future AML changes (Exh. BSG/SAB-1, at 50-51). In the past, the Department has authorized similar recording of a regulatory asset to avoid the significant reductions to stockholders' equity that result from the recognition of AMLs associated with pension and PBOP obligations. Boston Gas Company,

D.T.E. 03-1 (2003); Fitchburg Gas and Electric Light Company, D.T.E. 02-83 (2002); Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/NSTAR Gas Company, D.T.E. 02-78 (2002).

The Company recorded a charge to equity of $18,388,000 in 2002 as a result of recognizing its then-existing AML (RR-DTE-53). There is no assurance that future economic conditions and poor market performance will not produce the same and perhaps a more onerous result in the future. Although pension and PBOP expenses have been relatively stable in the past several years, the Company has experienced volatility in these expenses over a longer period of time (Exhs. BSG/SAB-1, at 48; DTE 8-9; Tr. 8, at 1316, 1319). We recognize that discount rates and investment returns on pension assets, which have a significant effect on pension obligations, have ranged between 6.25 percent and 19.9 percent between 2000 and the test year (Exhs. BSG/SAB-1, at 48; DTE 8-9). Recent, relative stability does not eliminate, but only masks, the inherent instability of this expense category. Future writeoffs, if they occur, could be of sufficient magnitude to have a material impact on the financial well-being of Bay State and translate directly into higher borrowing costs, higher rates, and a potential disruption in service. D.T.E. 04-48, at 17; NSTAR Companies, D.T.E. 03-47-A at 25-27 (2003); D.T.E. 03-40, at 308-314.

Based on these considerations, and consistent with Department precedent, we allow the Company to establish a regulatory asset for charges to equity resulting from the recognition of AMLs. This action enables Bay State to reverse the cumulative charge to equity recognized during the test year, but, more importantly, will provide the Company with a mechanism to

avoid potentially significant future charges, should economic conditions and poor market performance warrant the recording of significantly larger AMLs.

c. Reconciling Mechanism

Having determined that the Company may establish a regulatory asset for charges to equity based on the AML, we must decide whether it is appropriate to change the manner in which Bay State collects its pension and PBOP costs. Presently, the Company recovers its pension and PBOP costs through base rates. It now requests that we adopt a pension and PBOP reconciling mechanism that operates outside of base rates.

The Attorney General argues that the Department must reject the Company's proposal for a pension and PBOP adjustment mechanism because the tariff formula is not objective and does not require deposit of all funds collected into the respective trust funds (Attorney General Brief at 28). We conclude otherwise. With respect to the Attorney General's first point, pension and PBOP expenses are hardly determined in an arbitrary manner, but rather are calculated based upon the standards and requirements of SFAS No. 87 for pension expense and SFAS No. 106 for PBOPs (Exh. BSG/SAB-1, at 47). Once determined, the calculations are subject to review by the Company's accountants and actuaries. With regard to the Attorney General's concern over funding, the tax-deductible contributions to the respective plans are governed by rules and regulations set by the ERISA, administered by the IRS and, for the most part, beyond the control of the Company. For these reasons, we reject the Attorney General's position.

Bay State represents that the reconciling mechanism is necessary to demonstrate that the regulatory asset authorized by the Department for its AMLs and deferred pension and PBOP costs is "probable of recovery" pursuant to the requirements of SFAS No. 71 (Exh. BSG/SAB-1, at 50). Otherwise, according to the Company, the regulatory asset and deferrals would have to be written-off by a charge to its equity (id.). Department approval of the Company's request would allow it to increase its common stockholders' equity by $18,388,000 (RR-DTE-53).

The Department has ruled in the past that, when it has authorized the creation of a regulatory asset for AMLs and pension and PBOP deferrals, a reconciling mechanism is needed in order to address the "probable of recovery" requirements of SFAS No. 71. D.T.E. 03-47-A, at 27. Otherwise, the companies would not be allowed to continue to maintain the regulatory asset and record the deferrals. Id.

The Company's proposal for a reconciliation mechanism assures ratepayers that they would pay no more and no less than the Company's costs. A PAM keeps a pension plan on a sound footing every year and thereby promotes workforce stability and, with that, sound customer service. Id. at 27-28. The record establishes the presence of all factors that we have considered in the past in determining that an item should be recovered through a reconciling mechanism. The same factors that persuaded us to adopt the PAM in D.T.E. 03-47-A and D.T.E. 03-40 are present in the record before us: the magnitude and volatility of pension and PBOP expense; the role of accounting requirements in the pension and PBOP expense; and the effectiveness of the reconciling mechanism in avoiding the negative effects of pension and

PBOP expense volatility (Exhs. BSG/SAB-1, at 47-50; BSG/JAF-3, at 14; DTE 8-9; DTE 1-11;Tr. 8, at 1315-1321). Like Commonwealth Electric Company, Cambridge Electric Light Company, NSTAR Gas (formerly Commonwealth Gas Company), Boston Edison Company, (collectively, the NSTAR companies), Fitchburg Gas and Electric Light Company, and Boston Gas Company ("Boston Gas") before it, Bay State has demonstrated the value of a reconciling mechanism and its accord with our recent precedent. Moreover, the request is consonant with the Department's intent to develop "a consistent practice and treatment of these expenses henceforth, for all jurisdictional gas and electric companies." D.T.E. 03-47-A, at 6. We will allow the Company to implement the proposed PAM.

As we have for other companies that have a PAM, Bay State may recover not only its own deferrals, but also the carrying charges on prepaid pension and PBOP balances and unamortized deferrals. D.T.E. 04-48, at 15-18; D.T.E. 03-40, at 308-309; D.T.E. 03-47A, at 19-28. Moreover, we will adopt the Company's proposed amortization period for the deferrals of three years. Id.

d. Operation of PAM Mechanism

The Department will allow the reconciling mechanism to operate in the following way. As of December 1, 2005, the Company was be eligible to recover, outside of base rates, its test year SFAS-determined pension and PBOP amount. On September 15, 2006 and every year thereafter, as part of its LDAC, the Company will commence reconciling its SFAS-determined pension and PBOP expense for the prior calendar year, plus previously unamortized balances, with the amount included in rates during that period, and amortize that

amount over three years ("Reconciliation Amount"). In addition, the Company will be allowed to recover carrying costs applied to the average annual prepaid pension and PBOP balance expense and the unamortized deferred pension and PBOP expense, net of deferred income taxes.[84] The Reconciliation Amount and the carrying costs will be collected from, or refunded to, all customers on an equal cents per therm basis over the following twelve months through the Company's LDAC. The Company shall apply the prime rate on its reconciliation of forecast recovery to actual recovery consistent with 220 C.M.R. § 6.08 (2).

D. IBM Global Contract Savings

1. Introduction

NCSC has entered into a long-term contract ("Outsourcing Agreement") with IBM to contract various NCSC functions to this outside services provider (RR-AG-9 (Confidential)). The $1.5 billion contract is for a term of ten years with the option to extend for another five years (Exh. DTE 18-1(a), at 4; RR-AG-9 (Confidential)). Under the Outsourcing Agreement, NCSC will turn over to IBM significant portions of its functions, including human resources, meter to cash, finance & accounting, customer contract centers, supply chain, and information technology (RR-AG-10(a)(Confidential)). In turn, IBM intends to rely on third-party subcontractors to handle a number of these functions (RR-AG-9 (Confidential)). NiSource estimates that 572 of its employees and those of its subsidiaries are expected to become IBM

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[84] Carrying costs shall be based on the pre-tax weighted average cost of capital of 11.71 percent.

employees, and another 445 positions at NiSource and its subsidiaries will be eliminated (Exh. DTE 18-1, at 2).

NiSource announced in a SEC Form 8-K filing that it will achieve savings upwards of $530 million over the term of the contract (Exh. DTE 18-1(A), at 4). At the same time, NiSource estimates that it will incur approximately $21 million in one-time pension expense related to severed employees, $35 million in transition costs during 2005 and 2006 associated with the transfer of these functions to IBM, and $50 million in governance costs over the term of the contract (Exh. DTE 18-1, at 2-3).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that not only has the Company failed to pass along any savings from the IBM contract, but actually seeks to enrich NiSource at the expense of Massachusetts ratepayers (Attorney General Brief at 92; Attorney General Reply Brief at 41). Despite what the Attorney General characterizes as Bay State management's failure to respond appropriately to the needs of the Company's customers, the Company seeks to increase its test year cost of service to annualize new employees who will be terminated once the Outsourcing Contract is implemented (Attorney General Brief at 92; Attorney General Reply Brief at 42). The Attorney General contends that this will result in the inclusion of various "phantom" employee payroll, benefits, payroll taxes and NCSC charges, thereby resulting in double charges to the Company's ratepayers, and unjust enrichment to NiSource (Attorney General Brief at 92; Attorney General Reply Brief at 42).

The Attorney General states that the IBM contract with NCSC constitutes a known and measurable change in test year cost of service under Department precedent, and therefore the savings realized due to this contract should be removed from the Company's cost of service (Attorney General Brief at 91-92; Attorney General Reply Brief at 43). The Attorney General calculates that the annual savings to Bay State will be $3.43 million,[85] and maintains that the Department should reduce the Company's cost of service by this amount, as well as all other pro forma adjustments to payroll-related and NCSC charges (Attorney General Brief at 93-94, citing Exhs. DTE 18-1 (b), at 36; DTE 6-13; Tr. 21, at 3521-3524; RR-AG-10). The Attorney General contends that the costs associated with the Outsourcing Contract will be incurred in the early years of the proposed PBR plan, and should be amortized over the life of the contract (Attorney General Reply Brief at 43).

b. Local 273

Local 273 contends that throughout this proceeding, Bay State has sought to downplay the effect of the Outsourcing Contract on its operations (UWUA Reply Brief at 5). Local 273 points out that NiSource has made it clear that over 1,000 positions system-wide are expected to be outsourced, including over 100 positions at Bay State (UWUA Brief at 14). Despite this

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[85] The Attorney General calculated his savings estimate by first multiplying the Net Core Savings to NCSC of $395.8 million by 8.95 percent, representing the percentage of Net Core Savings associated with the eight functional areas the Company uses, producing $35.42 million (Attorney General Brief at 93, citing Exh. DTE 18-1(a) and (b); Tr. 20, at 3197-3198; RR-AG-10(b)). The Attorney General then divided that amount by ten years to obtain an annualized savings of $3.54 million, and reduced the annualized savings by an additional 3.18 percent for capitalized costs, resulting in an annual savings in O&M expense of $3.43 million (id. at 93, citing Exh. DTE 18-1(a) at 4; Tr. 21, at 3521-3524).

anticipated staff reduction, Local 273 argues that the Company's local management had virtually no input into NiSource's decision to enter into the Outsourcing Agreement and will have little involvement in its actual implementation (id.; UWUA Reply Brief at 5-6).

c. Steelworkers

The Steelworkers contend that the Company has not been forthcoming on the status and content of the Outsourcing Agreement, and has failed to provide critical information regarding the status of this contract to the Department and interveners (USWA Brief at 1-2). The Steelworkers also argue that the Company has not factored in any cost savings associated with the Outsourcing Agreement into the proposed rate increase (id. at 2, citing Exh. UWUA 3-8).

d. Company

Bay State argues that the Attorney General's proposed adjustment to cost of service for the Outsourcing Contract is speculative, inaccurate, and contrary to Department precedent (Company Brief at 11). The Company claims that there are presently no known savings associated with the Outsourcing Contract, and that a ten-year savings estimate provided in NiSource's SEC Form 8-K disclosure does not rise to the level of a "known and measurable" reduction to test year cost of service (id. at 12; Company Reply Brief at 19). The Company states that the Attorney General's estimates of benefits arriving from the Outsourcing Contract are far too speculative to use to adjust the Company's test year expenses, and that no savings at all will accrue to either NiSource or Bay State during the first year after the rate increase (Company Brief at 12, citing Exhs. DTE 18-1; AG 24-2; Company Reply Brief at 19-20). The Company argues that the Attorney General has provided no justification to deviate from the

Department's requirement that pro forma adjustments must occur in the rate year (Company Brief at 12, citing D.T.E. 02-24/25, at 76). Bay State argues that any consideration of "purported" Outsourcing Agreement savings should be deferred to the Company's next base rate proceeding at the end of its proposed Performance-based regulation term (Company Reply Brief at 20).

3. Analysis and Findings

The Department's precedent regarding O&M adjustments is well established. Proposed changes to test year revenues, expense, and rate base require a finding that the adjustment constitutes a "known and measurable" change to test year cost of service. D.T.E. 02-24/25, at 76; Dedham Water Company, D.P.U. 84-32, at 17 (1984). A "known" change means that the adjustment must have actually taken place, or that the change will occur based on the record evidence. D.T.E. 02-24/25, at 76. A "measurable" change means that the amount of the required adjustment must be quantifiable on the record evidence. Id.

The Department has previously rejected proposed adjustments for savings achieved by projects when the record showed that the savings are speculative or there was uncertainty that savings would be achieved in the rate year. D.T.E. 03-40, at 11; D.T.E. 02-24/25, at 76; D.P.U. 95-118, at 130-131; D.P.U. 92-111, at 142; Massachusetts Electric Company, D.P.U. 92-78, at 50-51 (1992). However, the Department has also found that improvements in technology and productivity that may be reasonably anticipated between the test year and the rate year, and which demonstrate a decrease in residual O&M expense as known and

measurable amounts, should be taken into consideration in setting rates. D.P.U. 92-78, at 47-48.

The Outsourcing Agreement has only recently been signed (Exh. UWUA-4, at 34; RR-AG-9 (Confidential)). While the Outsourcing Agreement specifies various areas of Bay State's operations that would be potentially affected, the Company has not concluded negotiations with union employees that would be required under the Company's collective bargaining agreements (Exh. DTE 18-1, at 2; RR-AG-10 (Confidential)). The outcome of such negotiations are, at this time, speculative. While we have no doubt that the reported $530 million reduction over ten years represent NiSource's best efforts to estimate the effect of a material change in condition as required under SEC reporting rules, the statements contained in an SEC Form 8-K disclosure do not rise to the level of demonstrating a "known and measurable" reduction to test year O&M expenses. D.T.E. 02-24/25, at 76; D.P.U. 84-32, at 17. Cf. D.P.U. 93-60, at 39-40 (cost of service reduced to recognize on-going implementation of automated meter reading system). Furthermore, because NiSource has yet to determine the allocation of cost savings among its affiliates, the Attorney General's calculation of savings arising from the Outsourcing Agreement is speculative at best (RR-AG-10 (Confidential)). Given NiSource's obligations for pension, transition and governance charges, it is unknown whether any savings at all will accrue to either NiSource or Bay State during the first year after the contract (Exhs. DTE 18-1; AG 24-2).

Timing is the heart of the problem here. It is clear that the Company and its parent expect some savings from the Outsourcing Agreement, but these are not yet calculable to the degree required by our precedent. Therefore, the Attorney General's proposed adjustment

does not meet the Department's known and measurable standard. D.T.E. 03-40, at 11; D.T.E. 02-24/25, at 76; D.P.U. 95-118, at 130-131; D.P.U. 92-111, at 142; D.P.U. 92-78, at 50-51. Accordingly, the Department will not adopt the Attorney General's proposal.[86]

E. Property and Liability Insurance

1. Introduction

Bay State's property and liability insurance coverage includes a number of types of insurance that provide protection from casualty and loss, and other damages that the Company may incur in the conduct of its business. During the test year, the Company booked insurance expenses of $2,301,379 (Exh. BSG/JES-1, Sch. JES-6 [Rev. 1] at 1(a)).

NCSC manages NiSource's corporate insurance program through which Bay State secures insurance coverage, for both premium-based and self-insured coverage (Exh. BSG/JES-1, at 18). The Company's insurance costs are initially charged to NCSC, and then allocated to Bay State and other NiSource affiliates based on individual allocation factors that vary by policy type and are designed to recognize the nature of the insurance coverage being allocated (Exhs. AG 1-61; AG 3-9; DTE 6-14 (Confidential)). The Company states that all of its insurance programs and policies are evaluated annually with the aid of insurance brokers in order to secure the best available coverage at the best available rate (Exh. BSG/JES-1 at 18). NiSource Insurance Company Limited, a subsidiary of NiSource, provides insurance coverage when the commercial market does not provide satisfactory

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[86] Issues related to the Company's staffing levels and outsourcing activities are separately addressed in Section X of this Order.

coverage or prices, and the availability of its services are considered in the Company's annual evaluation process (id. at 18-19).

In its initial filing, Bay State proposed an increase of $94,997 to test year insurance expense to account for known and measurable changes that it represents as having occurred during the test year and in 2005 (Exhs. BSG/JES-1, at 19; BSG/JES-1, Sch. JES-6, at 5). During the proceedings, the Company revised its proposed adjustment to a decrease of $75,116 to recognize the latest insurance premiums applied to its various liability policies; and because it was partially offset by the capitalization of 24.36 percent of its workers compensation insurance (Exh. BSG/JES-1, Sch. JES-6 [Rev. 1] at 5).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that a portion of the Company's workers' compensation expense should be allocated to construction activities, because workers' compensation expense is a component of overall labor costs (Attorney General Brief at 79). The Attorney General states that this should be accomplished by multiplying the Company's test year workers' compensation insurance expense of $673,516 by 24.36 percent, representing Bay State's test year allocation of wages and salaries to construction (id. at 80). The Attorney General determined that this would reduce Bay State's proposed cost of service by $164,069 (id.).

b. Company

Although Bay State agrees with the Attorney General that a portion of its workers' compensation insurance expense should have been capitalized, and revised schedules filed accordingly, the Company contends that the capitalization adjustment should be limited to its proposed adjustments for workers' compensation insurance and its self-insured portion of workers' compensation insurance (Company Brief at 82). The Company reasons that because a portion of its workers' compensation insurance had already been capitalized during the test year, it would be inappropriate to determine the capitalizable amount based on the total expense (id., citing Exh. AG 1-27(E) at 1). The Company argues that the appropriate decrease to its proposed workers' compensation insurance expense is not the Attorney General's proposed $164,069, but rather $137,538 (Company Brief at 82).[87]

3. Analysis and Findings

Rates are designed to allow for recovery of a representative level of a company's revenues and expenses based on an historic test year adjusted for known and measurable changes. D.P.U. 02-24/25, at 161; D.P.U. 92-250, at 106. As stated above, Bay State's insurance programs and policies are evaluated annually with the aid of insurance brokers in order to determine the appropriate form and price of coverage, including appropriate

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[87] Bay State calculated this adjustment by subtracting its test year workers' compensation insurance expense of $258,394 from its initially-proposed increase of $149,479, and multiplying that result by 24.36 percent (Company Brief at 82; Exh. BSG/JES-1, Sch. JES-6, at 5-6). This produces a decrease of $26,531 to the Company's proposed expense.

deductibles (Exhs. BSG/JES-1, at 18; DTE 6-20). The Department finds that the Company has taken reasonable measures to control its property and liability insurance expenses.

Concerning Bay State's workers' compensation insurance, the associated expense is booked to Account 925-06 and classified as "payroll liability insurance expense" for purposes of the Company's monthly allocation of charges to Northern Utilities (Exh. AG 1-27(E)). Bay State capitalizes a portion of its payroll liability insurance charges among its three operating divisions and its Westborough headquarters (id.). The Company's revised revenue requirement schedules adjust both the test year and pro forma workers' compensation insurance expense to recognize the capitalizable portion (Exh. BSG/JES-1, Sch. JES-6, at 5 (Rev.)). The Department finds, however, that Bay State inappropriately adjusted its workers' compensation insurance expense in the test year portion of its analysis. This distorts the test year expense level. The adjustment for this treatment should occur only in the Company's pro forma expense, thereby making the overall adjustment to workers' compensation insurance a decrease of $14,589. Along with other adjustments to insurance made by the Company that are approved by the Department, the Department decreases the Company's test year cost of service for insurance by $211,870, thereby approving workers' compensation insurance expense of $509,448 and total property and liability insurance expenses of $2,089,509.

F. Self-Insurance Claims

1. Introduction

Bay State maintains various deductibles for its property damage, auto liability, employee liability, and general liability, crime, and directors and officers liability insurance

policies, ranging between $200,000 and $10,000,000 (Exh. BSG/JES-1, at 20).[88] The Company self-insures these deductible portions through NiSource's corporate insurance program (id.). During the test year, the Company booked $397,749 in payments associated with its self-insurance claims (Exh. BSG/JES-1, Sch. JES-6, at 6 (Rev. 1)). The Company proposes an overall increase of $142,966 consisting of: (1) an increase of $351,374 in general liability self-insurance expense; (2) a decrease of $12,959 in auto liability self-insurance expense; and (3) a decrease of $195,449 in workers' compensation expense (id.). The Company determined these adjustments by taking the five-year average of claims for the years 2000 through 2004 for general liability and auto coverage, and eliminating test year workers' compensation self-insurance because of the elimination of the deductible for this coverage (Exhs. BSG/JES-1, at 20-21; BSG/JES-1, Workpaper JES-6, at 19). This produced a normalized self-insurance expense level of $477,770 (Exh. BSG/JES-1, Sch. JES-6, at 6 (Rev. 1)). However, the Company's proposed adjustment is based on an increase of $142,996 to the test year value of $397,749, producing a self-insurance claims amount of $540,745 (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company cites no precedent for its proposed five-year normalization of self-insurance claims expense (Attorney General Reply Brief at 32).

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[88] Bay State formerly maintained a deductible for its workers' compensation insurance, but eliminated this deductible on July 1, 2004, because of the volatility of costs being incurred by the Company as a result of various negative events affecting the insurance industry (Exhs. BSG/JES-1, at 20; DTE 6-20).

Moreover, the Attorney General contends that, by including a $1,000,000 insurance payment in 2003 for a 1998 house explosion in Attleboro, the Company skews the five-year average well beyond both the test year amount and its own claims loss history for the period 2001 through 2005 (id. at 32-33). Furthermore, the Attorney General argues that the record is devoid of any evidence supporting the Company's selection of deductibles, which results in a shift of risk from the Company's insurers to its ratepayers (id. at 33). The Attorney General concludes that the Company's approach does not produce a reliable measure of its self-insurance expenses (id. at 32, citing Exhs. AG-2; UWUA 1-11(c); D.T.E. 03-40, at 184; D.T.E. 02-24/25, at 161).

The Attorney General recommends that the Department use the Company's test year general liability self-insured expense of $204,375, resulting in an overall test year adjustment of $5,723 for all self-insurance expenses (Attorney General Reply Brief at 33). In addition, the Attorney General urges that Bay State be ordered to reduce its deductible for property damage from $1,000,000 to $200,000 (id.).

b. Company

Bay State opposes the Attorney General's proposed adjustment for self-insurance expense (Company Reply Brief at 31). The Company asserts that, because insurance claim levels are volatile, using a five-year average claim level is a reasonable method of obtaining a representative historical level for inclusion in rates (id.). Bay State notes that the five-year normalization period corresponds to its proposed performance-based regulation term of five years, produces a representative level of self-insurance expense in rates, and serves to smooth

out the average self-insurance claims expense in order to reduce the effects of insurable events that can affect a natural gas company on a year-to-year basis (id.). Finally, Bay State claims that the Attorney General's adjustment is mathematically incorrect, because he added rather than subtracted the book amount of claims to the actual claim amount (id.). The Company considers the Attorney General's proposed adjustment to be untimely and lacking a sufficient basis for the Department to adopt (id. at 31-32).

3. Analysis and Findings

The Department recognizes that because self-insured damage claims vary from year-to-year, limiting recovery to test year levels may not produce a representative level of claims expense on a forward-looking basis. See D.P.U. 87-59, at 35-40.

The Department finds that the Company incorrectly adjusted workers' compensation expense in the test year for capitalization (Exhs. BSG/JES-1, Sch. JES-6, at 6 [Rev. 1]). If an adjustment were warranted for capitalization, the adjustment would be made separate from the test year value. However, as the entire test year workers' compensation expense level is being eliminated, there is no need to make an adjustment to produce a normalized value, and therefore no adjustment for capitalization is needed for workers' compensation insurance expense. Therefore, the Department disallows the Company's decrease in test year self-insurance expense of $62,945 as revised by the Company.

The Company provided a claims loss run for general liability and auto liability covering the period from February of 2001 through May of 2005 (Exh. DTE 6-19). During this period, Bay State incurred 90 auto liability claims payments totaling $448,492, for an average payment

per claim of $4,983 (id.). All of these payments fell within the Company's current $200,000 deductible for auto liability coverage (Exh. BSG/JES-1, at 20). Therefore, this claim pattern represents an annualized auto liability self-insurance expense of $105,527.

During this same period, Bay State incurred 111 general liability claims payments totaling $652,651, for an average payment per claim of $5,880 (Exh. DTE 6-19). One of these claims, Claim AFP5238, involved a payment of $260,000, which exceeds the current general liability insurance deductible of $200,000 (Exhs. BSG/JES-1, at 20; DTE 6-19). Therefore, the Department finds it appropriate to adjust the average general liability claims payments to recognize that the Company's insurance carrier would be responsible for a portion of this payment. D.P.U. 87-59, at 39. After deducting the $60,000 in excess of the deductible for this claim, the revised claims payment are $592,651, representing an annualized general liability self-insurance expense of $139,447.

Based on the foregoing analysis, the Department finds that a representative level of self-insurance payments for auto liability coverage is $105,527, and $139,447 for general liability coverage. D.P.U. 87-59, at 39-40. With the elimination of workers' compensation self-insurance, the Department finds that the level of self-insurance claims to be included in cost of service is $244,974.[89] As a result of issues discussed above and the different methods employed by the Department and the Company in calculating self-insurance expenses, the Department will reduce Bay State's proposed cost of service of $540,745 by $295,741.

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[89] This expense level incorporates the Company's adjustments to its workers' compensation insurance expense.

G. Gains on Sale of Property

1. Introduction

Since the Company's last base rate case, it sold utility property at a gain on four occasions (Exh. BSG/JES-1, at 21). The transactions involve sale/leaseback arrangements for water heaters in 1995 and its Westborough headquarters in 1997, the sale of fully depreciated LNG trailers in 2001, and the sale of propane assets to EnergyUSA in 2001 (id., Sch. JES-6, at 7).[90] Bay State reported a net gain of $2,221,214, representing: (1) $426,182 associated with the water heater sale/leaseback; (2) $864,829 associated with the Westborough office sale/leaseback; (3) $700,000 associated with the sale of LNG trailers; and (4) $230,203 associated with the sale of propane assets (Exh. BSG/JES-1, Sch. JES-6, at7).

Bay State made two adjustments to recognize what it considered to be appropriate allocations to its affiliates and to non-utility operations (id. at 21-22). First, the Company allocated $141,832, or 16.4 percent, of the $864,829 of the gain related to the sale of the Westborough headquarters to Northern Utilities in order to recognize Northern Utilities' rental payments for its share of the facilities under the three-part formula used to allocate common costs between Bay State and Northern Utilities during the test year (id. at 21, Sch. JES-6, at 7). Second, the Company allocated $38,398, or 16.68 percent, of the $230,203 gain on the sale of all the propane properties to recognize the non-utility use of its propane facilities. In

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90 The propane properties were located in Brockton, Medway and West Springfield (Exh. DTE 1-1). In addition to these sales, Bay State executed long-term ground leases in 2001 with EnergyUSA for two other Company-owned propane facilities in Lawrence and Taunton (Exh. AG 3-44(1) at 44-45, 80-81 (Confidential)).

support of this allocation, the Company determined that a portion of a parcel of land in West Springfield with a book value of $58,736 that was included in the transaction had never been devoted to utility use and was never in rate base (Exhs. BSG/JES-1, at 22, Sch. JES-6, at 7 [Rev. 1]). The Company determined that $9,797 (16.68 percent) of that parcel of land was devoted to non-utility use (Exh. BSG/JES-1, at 21-22). Based on that ratio, the Company applied an overall non-utility allocation factor of 16.68 percent to its net gain on the sale of its propane properties, resulting in an allocation of $38,398 to non-utility operations (Exh. BSG/JES-1, Sch. JES-6, at 7 {Rev. 1}).

The total reported gain on the sale of property of $2,221,214, less $179,780 in affiliate and non-utility allocations, was $2,040,984 (id.). The Company proposes to amortize this amount over five years, representing the term of its proposed performance-based regulation, resulting in an annual reduction to test year cost of service of $408,197 (Exh. BSG/JES-6, at 7).

2. Positions of the Parties

a. Attorney General

i. Sale of Westborough Headquarters

The Attorney General maintains that the Company has incorrectly calculated the gain that should flow to its ratepayers due to the sale of its Westborough headquarters (Attorney General Brief at 38-39). As an initial matter, the Attorney General notes that the Company promised the Department it would not sell the Westborough property (Attorney General Reply Brief at 15, citing NIPSCo/Bay State Gas Acquisition, D.T.E. 98-31, at 50 (1998)). Secondly,

he points out that the Company sold the headquarters for $10,525,000, nearly $1 million below its original cost of $11,409,654, without the benefit of an appraisal or other market valuation (id., citing RR-AG-51; RR-AG-52). Next, the Attorney General maintains that the Company should calculate the gain based on gross proceeds less itemized sales costs, rather than net proceeds (Attorney General Brief at 39). The Attorney General argues that, by starting its computation with net proceeds, the Company failed to explain $1,264,381 of sale expenses and has denied the Department the opportunity to determine whether those expenses were reasonable and prudent (id.). In support of his position, the Attorney General points to two expenses deducted by the Company in computing the net proceeds – $276,000 for paving and $100,000 for attorneys' fees – which he contends neither appear on the June 30,1997 settlement statement nor are explained anywhere on the record (Attorney General Reply Brief at 15, citing RR-AG-49, Tab 2).

The Attorney General further argues that the Company wrongfully reduced the net gain on the Westborough office by $141,832 on the belief that certain affiliates should share in that gain (Attorney General Brief at 39). He notes that 26 Bay State employees and 22 NCSC employees occupy the 88,000 square feet of office space and that the Company is subleasing the remainder of the space (id., citing RR-AG-2; RR-UWUA-6). The Attorney General points out that the Company has not identified the sublessees, and has provided neither the square footage occupied by each sublessee or floor plans of the Westborough facility to assist in determining the degree to which the building is used for utility versus non-utility purposes (id. at 39-40). Because of these omissions, the Attorney General concludes that the Company is

unable to substantiate its claim that the affiliates who used the premises are entitled to any share of the gain from the sale (id. at 40).[91]

Finally, the Attorney General criticizes the Company for not conducting a proper cost/benefit analysis comparing the economic advantages of retaining the property with implementing a sale/leaseback arrangement (id.). He questions the Company's use of a one year cost/benefit analysis, rather than a 25-year life of the lease analysis (id., citing Tr. 9, at 1569-1570). Without such an analysis, the Attorney General maintains that the Company could not determine, nor could the Department review, whether a sale/leaseback would have produced more favorable results for ratepayers (Attorney General Brief at 40).

The Attorney General recommends that the gain on the Westborough sale/leaseback be calculated by taking the $11,409,654 original cost of the property on the date of the sale, and reducing that amount by $9,862,649, to recognize: (1) $278,726 in verified sales expenses; (2) $9,280,444 in net book value associated with the land and building; and (3) a $303,479 allocation of the gain to Northern Utilities (Attorney General Reply Brief at 16). The Attorney General considers that his revised gain of $1,547,005 is warranted because Bay State has not satisfied its burden of proof regarding either the economics of the transaction or its computation of the gain (id.).

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[91] In recalculating the portion of the Westborough gain that should flow through to ratepayers, the Attorney General did allocate a portion of that gain to the Company's affiliate, Northern Utilities (Attorney General Reply Brief at 16).

ii. Sale of Propane Properties

The Attorney General identifies the same flaws with the Company's gain on the sale of its propane facilities as he had set forth for the Westborough sale: i.e., (1) the Company's reliance on net proceeds in computing the gain; (2) the lack of a cost/benefit analysis to determine whether it was cheaper to own or lease the propane properties; and (3) the Company's failure to support its proposed allocation of the net gain to affiliates and non-utility operations (Attorney General Brief at 41-42). The Attorney General argues that Bay State's failure to perform a cost/benefit analysis is more egregious here than for the Westborough sale because the propane properties were sold to a NiSource affiliate, thereby raising a presumption that the transaction was not arms' length and may be subject to charges of self-dealing (id. at 42).

Moreover, the Attorney General contends that the Company failed to demonstrate that it complied with the Department's rules regarding the sale of assets to an affiliate (Attorney General Reply Brief at 17, citing The Berkshire Gas Company, D.T.E. 01-56, at 45 (2002)). The Attorney General considers that because the Company has not complied with the Department's rules and regulations governing affiliated transactions, the Department should, at a minimum, disallow the $38,398 deduction for the portion of gain allocated to Northern Utilities (id. at 18).

b. Company

i. Westborough Office Sale

Bay State maintains that it has properly calculated the gain on the Westborough office (Company Brief at 84). The Company contends that both the agreed purchase price of $10,800,000 and the net purchase price of $10,524,000 are clearly stated in the purchase agreement, as are the expenses of sale (id. at 85, citing RR-AG-49, Tab 1, ¶ 2.1; Tab 2, Items 1, 2; RR-AG-49, Tab 1, ¶ 9.3).[92] Bay State points out that the expenses of sale total $378,727, which when deducted from the net proceeds of $10,524,000, result in net proceeds of $10,145,273 (id. at 85; citing RR-AG-49). Moreover, Bay State argues that the Attorney General's proposal that the gain should be based upon the original cost at the date of sale, versus the purchase price, is inconsistent with Department precedent (Company Reply Brief at 16). Therefore, the Company concludes that the Attorney General's position on this matter should be rejected (Company Brief at 85).

The Company also disputes the Attorney General's claim that it improperly allocated a portion of the gain of the Westborough sale to Northern Utilities (id. at 86). The Company notes that all common costs and revenues are allocated to affiliates and that Exhibit AG 1-27 illustrates and documents the propriety of the 16.4 percent that was used to assign the gain to Northern Utilities (id.). In the Company's view, because Northern Utilities' customers supported the use of the building through their payments, a reasonable portion of the gain

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[92] The difference between the agreed purchase price of $10,800,000 and the net purchase price of $10,524,000 represents $276,000 in paving costs required as a "condition subsequent" term of the sale (RR-AG-49).

should be attributed to their benefit (id.). Bay State argues that, contrary to the Attorney General's claims, the Company provided floor plans, including a legend of common area to be subleased and rented space, along with a breakdown of square feet, including common space and rentable space (id., citing Exhs. AG 3-41(4); AG 3-28(2), at 5).

With respect to the Attorney General's cost/benefit analysis argument, Bay State maintains that it relied on its business judgement based on all available information at the time to conclude that it was reasonable to sell and lease back the Westborough facilities (id. at 87, citing Tr. 9, at 1567-1568). The Company contends that the transaction actually produced ratepayer benefits, because the sale resulted in a gain which flows back to customers, thereby reducing the revenue requirement in this case (id., citing Exh. BSG/JES-1, Sch. JES-6, at 7). Bay State concludes that, because the Attorney General can point to nothing indicating that the sale/leaseback decision was improper, his proposed adjustment should be denied (id.).

ii. Sale of Propane Properties

Bay State disputes the Attorney General's claims regarding the propriety of the sale of its propane facilities to EnergyUSA (id.). The Company argues that the assets sold were no longer needed to provide critical system pressure support (id. at 87-88, citing Exh. AG 3-44). Bay State points out that it competitively bid the sale of the facilities by placing a public Request For Proposal ("RFP"), but that no qualified third-party bids were received (id. at 88, citing Exh. AG-3-44).[93] Moreover, the Company contends that EnergyUSA is no longer an

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[93] The Company received one bid as a result of the RFP process conducted during the fall of 1999, but that bid was rejected because it did not meet the Company's expectations (continued…)

affiliate of Bay State (Company Brief at 88). In the Company's view, these factors undermine the Attorney General's position that the sale of propane assets was not an arms' length transaction (id.; Company Reply Brief at 17).

Bay State also opposes the Attorney General's proposal to reallocate the gain from the sale of the propane assets (Company Brief at 87). The Company contends that the propane facilities were supported by both Bay State and Northern Utilities ratepayers, and that a portion of the facility was in Northern Utilities' base rates (id.). Therefore, the Company argues that Northern Utilities' ratepayers should be credited with a portion of the gain from the sale, equal to the percentage of the costs they bore through their own distribution rates (id.). Bay State considers that crediting one hundred percent of the gain to Massachusetts customers would be "mathematically nonsensical" (id.).

3. Analysis and Findings

a. Introduction

The Department's long-standing policy with respect to gains on the sale of utility property has been to require the return to ratepayers of the entire gain associated with the sale, if those assets were recorded above-the-line and supported by ratepayers. D.P.U. 96-50 (Phase I) at 111; Barnstable Water Company, D.P.U. 93-223-B at 12 (1994); Commonwealth Electric Company, D.P.U. 88-135/151, at 92 (1989). Therefore, if such property is sold by the utility, it is necessary to include an adjustment which recognizes the appreciation on assets

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[93] (…continued)
(Exh. AG 3-44(5) (Confidential)).

that ratepayers have supported in rates through a return of and on investment. D.P.U. 88-135/151, at 91.

b. Sale of Westborough Office

The Attorney General criticizes the method used by the Company to calculate the gain associated with the Westborough office (Attorney General Brief at 38-39). However, the Attorney General's computation method on reply brief, and its reliance on original book value, actually serves to require the Company to pass back to customers the accumulated depreciation on the building less transaction costs. The Attorney General's method fails to recognize the factors that brought about the gain on the sale in the first place; i.e., the actual sales price for the property.[94] Consequently, the Department declines to adopt the Attorney General's proposed gain on the sale/leaseback of the Company's Westborough office.

In contrast, Bay State determined the gain on sale by first taking its gross proceeds of $10,800,000 and subtracting $276,000 in conditions charges to arrive at net proceeds of $10,524,000 (RR-AG-49, Tab 1, ¶ 2.1, Tab 2, Items 1 and 2).[95] The Company incurred

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[94] The Attorney General's analysis on his initial brief differs significantly from his analysis on reply brief. For example, in his initial brief, the Attorney General argues that the Company's calculation of the gain should begin with gross proceeds, not net proceeds, and that none of the gain should be allocated to Northern Utilities (Attorney General Brief at 39). In his reply brief, however, he maintains that the calculation of the gain should begin with the original cost of the property, and he allocates a portion of his calculated gain to Northern Utilities (id.; Attorney General Reply Brief at 16). Neither method is accurate.

[95] Although the purchase and sales agreement makes reference to a buyer's appraisal, the buyer waived the need for an appraisal because of Bay State's credit rating (RR-AG-52).

closing costs and related expenses of $378,727, thus resulting in net sales proceeds of $10,145,273 (RR-AG-49, Tab 2). From that amount, it then subtracted the net book value of the land and equipment of $9,280,444 to arrive at a gain of $864,829 (Exh. BSG/JES-1, Sch. JES-6, at 7 [Rev. 1]; RR-AG-49, Tab 1, ¶¶ 2.1, 9.3). Finally, the Company allocated a portion of the total gain to its affiliate Northern Utilities (Exh. AG 1-27). Bay State's computations are consistent with the general approach used by the Department to derive the gain or loss on a sale of utility property. D.P.U. 88-135/151, at 90-94.

Concerning the issue of a cost/benefit analysis for the sale/leaseback transaction, Bay State relied on a calculation that is comparable to what would be provided for cost of service purposes in a rate case (Exh. AG 3-42; RR-AG-49; Tr. 9, at 1569, 1582). A single year's analysis on a project with an anticipated life of 15 to 25 years is insufficient to establish whether actual savings would result from the transaction. Nevertheless, the Company's analysis in Exhibit AG 3-42, taking into consideration the lower rate base resulting from deferred income taxes not factored into this calculation, indicates that the first year's annual lease expense of $1,017,658 was less than the annual revenue requirement associated with owning the Westborough office of $1,676,786 (Exh. AG 3-42; RR-AG-51; Tr. 9, at 1587-1588).[96] Whether a similar result would occur over the life of the lease cannot be determined in this docket.

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[96] Bay State reported a net book value of $10,779,975 for the Westborough office at the time of the sale (Exh. AG 3-42). After deducting deferred income taxes of $178,031, the pre-tax return on rate base would decline from $1,406,787 to $1,383,554, and depreciation expense of $293,232 would remain unchanged (id.; RR-AG-48).

Accordingly, the Department requires Bay State, in its next rate case, to provide specific information that would enable the Department to compare the Company's expected lease expense over the life of the lease with the cost that would otherwise be incurred by the Company if it were to own the Westborough office, using a return on rate base analysis. The Company should demonstrate that the lease expense over the life of the lease does not exceed the long-run avoided cost of owning and operating the Westborough office. D.T.E. 88-135/151, at 86.[97] Moreover, the Company is directed to prepare a life-of-the-lease analysis of the comparative costs and benefits associated with a sale/leaseback of utility assets for all future sale/leaseback arrangements.

c. Sale of Propane Properties

As an initial matter, Bay State determined that its propane assets were no longer necessary because (1) distribution system upgrades eliminated the need to maintain the facilities to provide system pressure support, and (2) continued operation of the facilities in conjunction with other propane facilities that remained in use would result in operating system difficulties (Exh. AG 3-44). Under those conditions, it would be reasonable to conclude that continued ownership of plant that was no longer useful in providing service to ratepayers and was no longer cost-effective. See D.T.E. 01-56, at 42-43; D.P.U. 93-60, at 41-44. Therefore, the Department finds that there was no need for Bay State to perform a cost-benefit

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[97] If the results of the analysis demonstrate that the lease expense over the life of the lease exceeds the long-run avoided cost of owning and operating the Westborough office, the Department may limit the lease expense to an amount equal to the annual revenue requirement associated with ownership of the Westborough office.

analysis of the type sought by the Attorney General for the sale/leaseback of its propane facilities.

Bay State sold the propane properties to EnergyUSA in December of 2001 (Exh. AG 3-44). At the time of the sale, EnergyUSA was an affiliate of NiSource, having been acquired in April of 1999 (Exh. AG 1-2(10), 2001 Statistical Summary at 9).[98] By virtue of NiSource's common ownership of Bay State and EnergyUSA, the Company was an affiliate of EnergyUSA pursuant to G.L. c. 164, § 85(b). Under the Department's standards of conduct governing electric and gas distribution company affiliates, the sale or transfer of any assets to EnergyUSA must be at the higher of net book value or market value of the asset. 220 C.M.R. § 12.04(1). Bay State initially issued an RFP for the sale of its propane facilities in 1999, and received one bid which it rejected as unacceptable (Exh. AG 3-44(5) (Confidential)). In 2001, the Company reevaluated the situation and found a qualified buyer for the propane facilities (Exh. AG 3-44).[99] The fact that no acceptable bids were received in 1999 does not demonstrate that the RFP process was flawed. Rather, the lack of a successful RFP is more indicative of the state of the market at that time for fixed-location propane facilities. Given the specialized nature of the assets being sold and the lack of qualified bids in

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98 Bay State argues on brief that at the time of the sale/leaseback transaction, EnergyUSA was both an affiliate of NiSource, and not an affiliate (Company Brief at 7). The argument does not cohere. As noted above, EnergyUSA was an affiliate of Bay State at the time of the sale.

99 The Company reported a total gain on the sale of propane facilities because a parcel of land in West Springfield was included in the sale (Exh. BSG/JES-1, at 21-22; AG 3-44(1) at 114).

1999, there is no basis to conclude that an RFP issued in 2001 would have elicited more interest from third-party bidders. The entire net gain of $230,203 associated with the sale of the propane facilities was attributed to the parcel of land in West Springfield, with the actual facilities being sold at book value (Exh. BSG/JES-1, at 21-22). The Department finds that the sale of Bay State's propane assets to EnergyUSA in 2001 was an arms' length transaction in compliance with the requirements of 220 C.M.R. § 12.04(1).

Turning to Bay State's total gain on the sale of the propane properties for allocation purposes only, the land had a book value of $58,736, of which $9,797, or 16.68 percent, had been classified as non-utility property and was never included in rate base (Exh. BSG/JES-1, at 21-22).[100] The Department finds that the Company has appropriately allocated the $230,203 gain associated with this transaction between utility and non-utility operations. Additionally, the Department finds that Bay State's computations are consistent with the general approach used by the Department. D.P.U. 88-135/151, at 90-94. Accordingly, the Department finds that the total gain on the sale of the Company's propane facilities was $191,805.

d. Conclusion

Based on the foregoing, the Department finds that the total gain associated with the four property sales that occurred between 1995 and 2001 is $2,040,984. The Department also finds that a ten-year amortization of the gain is appropriate as consistent with the ten-year term for

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[100] On brief, the Company argues that its allocation was appropriate because Northern Utilities supported some of the costs of the propane facilities and, therefore, Northern Utilities' customers deserve credit for a portion of the gain (Company Brief at 88). There is no evidence that Bay State's propane facilities in Massachusetts were ever used to meet Northern Utilities' supply or reliability requirements.

the PBR being approved in this Order. This produces an annual amortization of $204,098. Accordingly, the Company's proposed cost of service shall be increased by $204,098.

H. Rate Case Expense

1. Introduction

In its initial filing, Bay State estimated it would incur $1,658,500 in rate case expense (Exhs. BSG/JES-1, at 25; BSG/JES-6, at 8). On September 30, 2005, the Company reported that its total rate case expense was $2,450,223 (Exh. DTE 15-58 (Supp. 6) at 8). Bay State proposed to amortize the rate case expense over the five-year term of its proposed performance based rate plan (Exh. BSG/JES-1, at 25).[101]

The Company's rate case expense includes: (1) legal representation; (2) research and preparation of a productivity and cost study to support the price-cap component of the performance-based rate plan; (3) a depreciation study; (4) cost of capital research; (5) research and analysis for the steel infrastructure retirement program; (6) a labor and benefit analysis; (7) other professional services; and (8) other associated costs that were incurred to complete the case, such as copying, supplies and temporary help (Exh. DTE 15-58 (Supp. 6) at 8). In addition, the Company has provided an estimate of remaining rate case expense of $67,540 (id.).

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[101] The proposed annual amount of $490,045 was based on the latest rate case expense estimate and a five-year performance-based regulation plan (Exhs. BSG/JES-1, at 25; DTE 15-58 (Supp. 6) at 8).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should exclude a number of rate case expenses because the Company failed to: (1) determine that ratepayers will benefit from the expenses; and (2) conduct competitive bidding for several of the outside services (Attorney General Brief at 85). The Attorney General contends that expenses associated with Hewitt for pension and PBOP reports do not belong in the rate case because: (1) Bay State pays Hewitt an annual retainer; (2) the Company did not sponsor a representative from Hewitt at the hearings, therefore precluding any cross-examination as to the reasonableness of the expenses; (3) ratepayers did not benefit from Hewitt's services; and (4) Hewitt's services were not competitively bid for the rate case (id.).

The Attorney General likewise contends that the expenses of R. J. Rudden for services related to Bay State's proposed SIR program should also be excluded from rate case expense (id.). The Attorney General argues that the Department should remove these expenses because the Company did not use the reports prepared by R.J. Rudden in support for its SIR program (id.).

The Attorney General also identifies expenses from Yardley and Associates ("Yardley") that he claims appear to represent duplicate services to those provided by Mr. Ferro (id. at 85-86). The Attorney General contends that because no witness for Yardley was made available for cross-examination, the reasonableness of this expense can not be ascertained (id.).

The Attorney General maintains that the Company included expenses from Corporate Renaissance for a service quality performance audit (id. at 86). The Attorney General adduces that this type of expense is more appropriately allocable to the preparation of the Company's annual service quality report, rather than legitimate rate case expense (id.). Therefore, the Attorney General recommends that the Corporate Renaissance expenses be excluded from rate case expense (id.).

The Attorney General argues that all meal expense should be excluded from rate case expense because there is no demonstrable benefit to ratepayers (id.). Along with meal expenses, the Attorney General also notes that floorplans and blueprints provided by Coler and Colantonio contained expenses allocable to Northern Utilities, rather than Bay State, and this expense should be removed from rate case expense (id. at 86-87). Finally, the Attorney General contends that expenses included by the Company for a Konica copy machine may have been billed twice – once via Konica and once via Bank of America Leasing (id. at 87).

b. Local 273

Local 273 questions "management's competence" in managing the rate case. Local 273 contends that many of the Company's responses to its information requests in the case were not filed in a timely fashion (Local 273 Brief at 8-10). Local 273 also notes that it was forced to file a motion to compel to obtain its information requests by a date final, in order to write its briefs (id. at 9). Local 273 indicates that despite its motion to compel, the Company still failed to meet the date final for responding to information requests (id.).

Local 273 maintains that its ability to fully participate in the rate case was prejudiced (id.). Local 273 also suggests that management should have arranged for the necessary staff and other resources to respond in a timely fashion to discovery in the case (id. at 10). Local 273 contends that in the context of seeking over one million in rate case expense, the Company is obligated to act prudently and devote an adequate portion of its resources to make sure that intervenors are not prejudiced as a result of untimely answers to discovery (id.). Local 273 contends that the Company's failure to "marshall the resources necessary for not only preparing the Company's direct case but for answering discovery as well" should be a factor the Department considers in setting the Company's allowed return on equity (id.).

c. Company

Bay State contends that 82 percent of its total estimated rate-case expense was competitively bid (Company Brief at 89). The Company also contends that those services that were not competitively bid represented service providers that possessed "unique familiarity with Bay State's operations, competitive rates, and ability to provide the requested services in an efficient and timely manner" (id. at 90).

The Company argues that the Attorney General is "illogical" in recommending exclusion of certain rate case expenses because of the absence of a ratepayer benefit (id. at 92). Bay State contends that a utility is not required to demonstrate a ratepayer benefit to justify rate case expense under Department precedent. Additionally, the Company contends that it is also not required for the Company to present a witness to represent each study or consultant's activity contained in the rate case (id. at 93).

The Company argued that the work performed by Hewitt did not fall within its broader contract with NiSource (id.). The Company asserts that the work performed by Hewitt consisted of analyses required under Department practice to demonstrate reasonableness of compensation packages, and that other work performed by Hewitt for NiSource, such as a 2004 wage and compensation analysis and advice on actuarial pension and PBOP issues, was not included in rate case expense (id. at 93-94). The Company concludes that the rate case expense from Hewitt is justifiably recoverable (id.).

Regarding its expenses from R.J. Rudden, Bay State contends that these services were competitively bid and the Company considered that an outside expert should evaluate the Company's SIR program (id. at 94, citing Tr. 6, at 1054-1057). Consequently, the Company contends that it is improper to remove the R.J. Rudden expense (Company Brief at 94).

Likewise, the Company argues that the Yardley expenses are equally valid (id. at 95). The Company contends that the services provided by Yardley assisted Mr. Ferro in the preparation of the case, and that the expertise of the firm was of invaluable assistance in the preparation of Mr. Ferro's testimony and responses to discovery (id.).

With regard to the expenses incurred for the service quality work performed by Corporate Renaissance, Bay State contends that it retained Corporate Renaissance to perform a service quality performance audit (id. at 96). The Company argued that engaging a firm for the purpose of the audit reduced rate case expense by removing an issue of contention from the rate case (id.). The Company asserts that contrary to the Attorney General's assertion,

Corporate Renaissance was not engaged to prepare the Company's Service Quality reports, and thus these costs should be included in rate case expense (id.).

The Company argues that meal expenses should be allowed (id.). The Company argues that the majority of meals were weekend and night meals for staff in Westborough, or for experts and outside consultants for hearings in Boston (id. at 96-97). Bay State argues that meals are required in Westborough because there are no restaurants within walking distance of the Company's offices, and that consultants have to charge for meals when traveling significant distances overnight (id.).

Concerning the building allocation study by Coler and Colantonio, Bay State contends that the study was required to support the Company's burden of proof on as to whether the appropriate amount of building space was allocated to affiliates in the cost of service (id. at 95). The Company concedes that it had inadvertently included expenses from Coler and Colatonio in its cost of service that should more appropriately be allocated to Northern Utilities, and has now removed them from rate case expense (id., citing RR-DTE-144).

3. Analysis and Findings

a. Introduction

The Department allows recovery for rate case expenses if the expenses are known and measurable. D.T.E. 01-56, at 75; D.P.U. 84-32, at 17. The Department has cautioned that rate case expense, like any other expenditure, is an area where companies must seek to contain costs. D.T.E. 02-24/25, at 192; D.P.U. 96-50 (Phase I) at 79. Below we address the issues

of competitive bidding, contested rate case expenses, estimated remaining rate case expense, and the normalization period for rate case expense.

b. Competitive Bidding

The Department has repeatedly advised companies to contain rate case expenses, and that obtaining competitive bids for consultant services is an important part of containing this expense. In an effort to control these costs, the Department has stated that we will approve expenses for outside legal and consulting services not competitively bid only if the company provides adequate justification for its decision to forgo the bidding process. D.T.E. 02-24/25, at 192; D.T.E. 01-56, at 76; D.T.E. 98-51, at 59-60; D.P.U. 96-50 (Phase I) at 79.

In the instant case, the situation appears significantly different. The Company put out for competitive bid the vast majority of its consulting and legal requirements (Exh. BSG/JES-1, at 23).[102] In fact, 82 percent of the Company's rate case expense was subject to a competitive bidding process (id.). Those services not put out for competitive bid by Bay State included those where pre-existing knowledge of the Company, prior competitive rates, and the ability to provide the services in a timely fashion were of critical importance in the selection of those firms (id. at 23-24). In the instant case, the Department finds that the

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[102] The depreciation work, performance-based regulation studies, cost of capital research, marginal cost and cost of service studies, the market based allocation study, the SIR research, and outside legal representation were all put out for bid by the Company (Exh. BSG/JES-1, at 23). Those items not put out to competitive bid included the Hewitt research on pension and PBOP, temporary consultants hired to help prepare the case, temporary clerical help, and administrative fees such as copying and document preparation.

Company has taken prudent action to control rate case expense by putting out for competitive bid most of the services required by the Company.

c. Contested Rate Case Expenses

The Attorney General contests a number of items included by the Company in rate case expense. The Attorney General contends that the expenses by Hewitt for pension and PBOP analysis do not belong in the rate case for many reasons, including: (1) Hewitt is paid on an annual retainer; (2) the Company did not present a witness from Hewitt for cross-examination; (3) ratepayers did not benefit from Hewitt's services; and (4) the Hewitt services were not competitively bid. The record provides little support for the Attorney General's position. The evidence indicates that the work performed by Hewitt was not covered as part of the Company's annual retainer, but was specifically produced by Hewitt to support the Company's rate case (Exhs. BSG/SAB-1, at 44-48; DTE 15-58 (Supp. 1) at 1-16). Second, the record also demonstrates that, because Hewitt already had intimate knowledge of Bay State's data and human resource issues, Hewitt was a rational choice to conduct the pension and PBOP study required by the rate case because competitive bidding, in this particular case, was unlikely to lead to a lower cost for the study (Exh. AG 12-6 (Confidential)). Finally, the Department has not historically disallowed rate case expenses solely because a company decides not to sponsor a witness to support a study or because a company failed to show a "ratepayer benefit" from an expenditure required to complete a rate case. Based on the above considerations, the Department finds that the Hewitt services are eligible for inclusion in rate case expense.

Concerning the R.J. Rudden expense, the Attorney General contends that because the Company did not use the R.J. Rudden study as support for its SIR program, the expense should be excluded. Analysis of the record does not support the Attorney General's recommendation and, in fact, supports a contradictory finding. Throughout the case, the R.J. Rudden study was cited numerous times.[103] Further, Mr. Bryant testified that the study was valuable to Bay State because it provided independent confirmation by outside engineering experts that the Company was examining its proposed SIR program properly (Tr. 20, at 3303-3304 (Confidential)). The Department finds that the R.J. Rudden study had benefit for ratepayers. Therefore, the Department also finds that the cost of the R.J. Rudden study shall be included for recovery as rate case expense.

Next, the Department will consider the expenses for Yardley. The Attorney General contends that Yardley's scope of work was duplicative of the work for the rate case contributed by Mr. Ferro. Examination of the statements submitted by Yardley suggest that their scope of work supplemented that of Mr. Ferro. For example, Yardley contributed to brief development and tariff development (Exhs. DTE 15-58 (Supp. 1) at 12; DTE 15-58 (Supp. 6) at 3). Therefore, the record evidence does not support the contention of the Attorney General. The Department finds that the Yardley expenses should be included in rate case expense.

We will now turn to disallowances. First, the Department disallows $25,150 allocable to Corporate Renaissance. Analysis of the invoices provided by Corporate Renaissance indicates that almost all of its scope of work was performed to complete the Company's service

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[103] The Department found the study referenced 38 times during the evidentiary hearings.

quality report for the year 2004-2005 (Exh. DTE 15-58 (Supp. 1) at 14-15)). For example, Corporate Renaissance reported that they collected data for all of reporting measures called for in the annual service quality report required to be filed by the Company (id.). Corporate Renaissance also reported that they collected data for all of the Company's service quality measures that were subject to a monetary penalty in the Company's annual SQ report to the Department (id. at 16-17). Ratepayers should not have to bear special, incremental charges for work the Company normally performs itself. Therefore, the Department finds this expense to be an unnecessary rate case expense, and will reduce the Company's proposed rate case expense by $25,150.

The Department has identified $1,219 in meal expenses included in rate case expense. Previously, the Department has ruled that while companies may choose to reimburse its employees for personal expenses, the mere fact that such expenses are incurred does not make it reasonable for the company to recover the items via rate case expense. See D.T.E. 03-40, at 161. Reimbursement of employees for miscellaneous items such as meals and parking based on receipts permits no consideration by the Department of whether the expenses are reasonable. Therefore, recovery of these rate case expenses cannot be allowed. D.T.E. 03-40, at 161. Accordingly, the Department will reduce the Company's proposed rate case expense by $1,219.

Regarding the Coler and Colantonio expenses, the Company has consented to reduce its rate case expense by $3,077 which is Northern Utilities' allocated percentage of the building

allocation study (RR-DTE-144; Company Brief at 95). Therefore, net of the $3,077 allocation to Northern Utilities, the Department approves the Coler and Colantonio expenses.[104]

The Attorney General argues that expenses included by the Company for copying expenses from Konica and Bank of America Leasing were duplicative. The record does not support the contention of the Attorney General. Department analysis of the dates on the statements and the description of the billed items suggest that different time periods and different descriptive items were the subjects of the statements. As a result, the Department finds that the statements from Bank of America and Konica do not represent twice-billed services, and therefore, the expenses are includable by the Company as rate case expense.

The Department has identified $9,115 in expenses for miscellaneous office services that are reflected as a "fixed" bill charge (e.g., Exh. DTE 15-58 Bulk (c) at 1; Exh. DTE 15-58 (f) at 1; Exh. DTE 15-58 (h) at 1; Exh. DTE 15-58 (g) at 34). The Department has denied fixed company "adders" to statements based on a percentage allocable to telephone, reproduction, data processing, etc. because it is impossible to determine if the expenses are reasonable, since the expenses are not itemized. D.T.E. 03-40, at 159; D.T.E. 02-24/25, at 194. In the instant case, the Department again finds these fixed adders to be unexplained. Therefore, the Department will reduce the Company's proposed rate case expense by $9,115.

As a result of the foregoing analysis, the Department finds that the Company's proposed rate case expense shall be reduced by $35,484.

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[104] The Company has included this adjustment in its revised rate case expense (Exh. BSG/JES-1, Workpaper JES-6, at 20.)

d. Normalization Period

The proper method to calculate a rate case expense adjustment is to determine the rate case expense, normalize the expense over an appropriate period, and then compare it to the test year level to determine the adjustment. D.T.E. 02-24/25, at 197; D.T.E. 98-51, at 62; D.P.U. 95-40, at 58. The Department's practice is to normalize rate case expenses so that a representative annual amount is included in the cost of service. D.T.E. 02-24/25, at 191; D.T.E. 01-56, at 77; D.T.E. 98-51, at 54; D.P.U. 96-50 (Phase I) at 77; The Berkshire Gas Company, D.P.U. 1490, at 33-34 (1983). Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense, rather, it is intended to include a representative annual level of rate case expense. D.T.E. 02-24/25, at 191; D.T.E. 01-56, at 77; D.P.U. 96-50 (Phase I), at 77; D.P.U. 91-106/138, at 20.

In the case where a company is proposing a PBR plan, the Department will also look at the term of the PBR plan.[105] If the term of a PBR plan exceeds the average frequency between a company's most recent rate proceedings, as determined above, the Department uses the term

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[105] Where there is no performance-based regulation plan, the Department determines the appropriate period for recovery of rate case expenses by taking the average of the intervals between the filing dates of a company's last four rate cases (including the present case), rounded to the nearest whole number. D.T.E. 02-24/25, at 191; Nantucket Electric Company, D.P.U. 91-106/138, at 19-20 (1991); D.P.U. 1490, at 33-34. Application of this precedent results in a normalization period of 5 years as follows: Bay State's last four rate cases were D.T.E. 05-27 (filed April 27, 2005), Bay State Gas Company, D.P.U. 97-97 (filed October 9, 1997, D.P.U. 92-111 (filed April 16,1992), and Bay State Gas Company, D.P.U. 89-81 (filed April 14, 1989). The sum of the three time intervals between these cases (7.5 plus 5.6 plus 3.0), divided by three and rounded to the nearest whole number, results in a normalization period of five years.

of the PBR plan as the normalization period for the rate case expense. D.T.E. 01-56, at 77; D.P.U. 96-50 (Phase I) at 78-79; D.T.E. 03-40, at 163-164.

Bay State proposed to normalize its rate case expense over the term of its proposed five-year PBR plan (Exhs. BSG/JES-1 at 25; DTE 15-58 (Supp. 6) at 1). As discussed in Section IX.C.3 below, the approved term of the Company's PBR plan is ten years. The Department has now established considerable precedent that companies under a PBR plan shall use a normalization period for rate case expense that corresponds to the length of the PBR plan. See D.P.U. 96-50 (Phase I) at 78; D.T.E. 01-56, at 77; D.T.E. 03-40, at 164-165). Therefore, the Department finds that the Company shall use a normalization period of ten years. This results in an annual rate expense amount of $241,474.[106]

e. Conclusion

The Company has requested recovery of rate case expense of $2,450,223 (Exh. DTE 15-58 (Supp. 6) at 8). Of this amount, the Department disallows $35,484, as set forth above, and approves a rate case expense of $2,414,739. This amount is $756,239 higher than the Company's original rate case expense estimate of $1,658,500.

Based on the findings above, the Department concludes that the correct level of normalized rate case expense is $241,474 ($2,414,739 divided by ten years). Because Bay State proposed a normalized rate case expense of $490,045, the Company's proposed cost of service will be reduced by $248,571.

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[106] The annual expense amount is the total approved rate case expense, $2,347,299, divided by the approved performance-based regulation period of ten years.

I. Bad Debt Expense

1. Introduction

The Department permits a representative level of uncollectible revenues (i.e., bad debt) as an expense to be included in rates. During the test year, the Company booked $9,794,694 in bad debt expense (Exhs. DTE 9-25; RR-DTE-37). In addition, the Company booked during the test year $412,767 in bad debt expense associated with its unregulated EP&S business (Exhs. BSG/JES-1, at 26-27; BSG/JES-1, Sch. JES-6, at 10 [Rev. 1]).[107]

For its utility operations, the Company proposes to calculate bad debt expense by comparing its net write-offs in the years 2002 through 2004 to firm billed revenues in the same period (Exh. BSG/JES-1, Sch. JES-6, at 9 [Rev. 1]). The resulting bad debt ratio of 2.15 percent [108] was multiplied by the normalized firm sales revenues during the test year of $475,323,113, which yields a bad debt expense allowance of $10,219,447 (id.). Because $7,058,572 of this bad debt expense allowance will be collected through the Company's CGAC, the distribution related portion amounts to $3,160,875, i.e., $10,219,447 - $7,058,572

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[107] The Company states that its unregulated EP&S business is integrated into its gas utility operations and that the Department requires that such above-the-line activities must be profitable on an incremental basis (Exh. BSG/SHB-1, at 51-52). The Company claims that its EP&S business contributed $5.7 million of profit in the test year that directly offsets expenses that would otherwise be borne by ratepayers (id. at 58).

[108] The Company's initially-proposed three-year average net write-offs was 2.17 percent (Exh. BSG/JES-6, at 9). During the proceeding, the Company discovered that the initially-filed total firm billed revenues of $301,555,112 for 2002 was incorrect and the correct amount should be $314,644,583, resulting in a revised three-year average net write-offs of 2.15 percent (Exhs. DTE-9-20 [Rev. Supp.]; BSG/JES-6, at 9 [Rev. 1]; Tr. 8, at 1409-1413).

(Exh. BSG/JES-1, Sch. 4 (Rev. 1)). Subtracting the distribution related bad debt expense of $3,160,875 from the actual test year bad debt expense of $3,199,694[109] results in the proposed reduction of actual test year bad debt expense of $38,919 (Exh. BSG/JES-1, Sch. JES-6, at 9 (Rev. 1); see RR-DTE-37). The Company also proposes an additional adjustment of $465,973 (=$21,673,150 X 0.0215), representing the amount of uncollectible expense adjustment associated with the proposed revenue increase of $21.7 million (Exh. BSG/JES-1, Sch. JES-1, lns. 1, 4 [Rev. 1]).

Regarding its EP&S business, the Company similarly proposes to calculate bad debt expense by comparing its annual net write-offs in the years 2002 through 2004 to annual revenues in the same period, resulting in a bad debt ratio of 4.54 percent (Exh. BSG/JES-1, Sch. JES-6, at 10 [Rev. 1]). Then the Company multiplied this ratio by the EP&S normalized sales revenues during the test year of $14,515,392, which yields a bad debt expense allowance of $658,999 (id.). The Company then reduced this amount by the test year bad debt expense of $412,767, giving its proposed $246,232 uncollectible expense adjustment (Exhs. BSG/JES-1, at 26-27; BSG/JES-1, Sch. JES-6, at 10 [Rev. 1]). The Company claimed that its calculations of bad debt expense are consistent with existing Department standards (Exh. BSG/JES-1, at 26).

For ratemaking purposes, Bay State proposed to recover a portion of the total allowable uncollectible expense through the base distribution rates and recover the gas cost-related bad

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[109] The $3,199,694 test year distribution related bad debt expense was determined as the $9,794,694 total booked bad debt accrual for 2004 less $6,595,000 CGA includible bad debt (Exh. DTE-9-25; RR-DTE-37).

debt through the Cost of Gas Adjustment ("CGA"). More specifically, based on its allocated cost of service study, the Company functionalized the pro forma uncollectible expense identified in its cost of service study into distribution and gas supply related costs (Exhs. BSG/JES-1, Sch. JES-6, at 9 [Rev. 1]; BSG/JLH-2, at 23; DTE 9-2; DTE 9-25; DTE 9-26; RR-DTE-25). The Company stated that its proposed CGAC tariff provides for the same method of recovery for gas cost-related bad debt that is currently in place (Exh. AG 22-12, citing Exh. BSG/JLH-1, Sch. JLH-1-7; see Exh. BSG/JAF-3-1, M.D.T.E. No. 36, §§ 6.0, 15.0). The Company added that its intent is to recover dollar-for-dollar the costs of all CGA costs that are written off (Exh. AG 22-12; Tr. 3, at 629-630). Regarding the uncollectible expense adjustment associated with its EP&S business, the Company proposed that the amount be recovered through the base distribution rates, stating that it does not recover any portion of its EP&S related bad debt through the CGA (Exhs. BSG/JLH-2, Sch. 2-2, at 12-1; DTE 9-19).

2. Positions of the Parties

a. Attorney General

The Attorney General notes that the Company proposed to continue its current bad debt recovery mechanism for both the distribution base rates and the CGA components as approved in D.T.E. 97-97 (Attorney General Brief at 68). The Attorney General also notes that the Company calculated the bad debt component for recovery in the base distribution rates in a manner consistent with prior Department precedent (id. at 68-69, citing D.T.E. 03-40, at 267; D.T.E. 02-24/25, at 171; D.T.E. 01-56, at 96; D.P.U. 96-50 (Phase I) at 72-73). The

Attorney General, however, recommends that the Department reject the Company's proposal relating to the CGA component of allowable bad debt expense because it does not comply with and deviates from current Department precedent established in D.T.E. 02-24/25 and D.T.E. 03-40 (Attorney General Brief at 68-69, 72).

The Attorney General states that although the CGA component of bad debt was initially estimated, the Company reconciled the estimate to actual net write-offs such that currently it recovers dollar for dollar its gas cost-related bad debt through its CGA (Attorney General Brief at 69, citing Exh. AG-22-12; Tr. 6, at 1011-1012; Tr. 3, at 629-630). The Attorney General, however, claims that the Department changed its policy in D.T.E. 02-24/25 by stating that dollar-for-dollar recovery removes the incentive for a company to reduce its bad debt expense (id. at 70, citing D.T.E. 02-24/25, at 172). He states that the Department directed the company to apply each year's allocation factor to the level of bad debt approved in the rate case, such that the company shall not recover more than the level of bad debt expense approved in the rate case (id., citing D.T.E. 02-24/25, at 172). The Attorney General adds that the Department affirmed this method in D.T.E. 03-40 (id., citing D.T.E. 03-40, at 267).

The Attorney General claims that the Company failed to provide any evidence or perform any studies to support its proposed deviation from current Department precedent (Attorney General Brief at 71). In addition, the Attorney General claims that the Company did not quantify the risk it would be exposed to if the Department were to direct Bay State to follow the bad debt recovery method established in D.T.E. 02-24/25 and D.T.E. 03-40 (id., citing Tr. 6, at 1084-1087).

The Attorney General also contends that the Company's proposal, to increase total bad debt expense by an amount equal to the product of its proposed revenue requirement increase and the three-year average net write-offs, is not consistent with Department precedent (Attorney General Brief at 69, citing D.T.E. 02-24/25, at 172; and D.T.E. 03-40, at 267). In addition, the Attorney General contends that the Company has not shown that the higher average percent net write-offs applicable to the EP&S is just and reasonable or the result of prudent operations (Attorney General Brief at 75). Therefore, the Attorney General recommends that the Department reject the EP&S bad debt adjustment and reduce the Company's proposed cost of service by $246,232 (id.).

The Attorney General rejects the Company's claim that using the method in D.T.E. 03-40 would cause a significant shortfall in the collection of gas cost-related bad debt and render the Company vulnerable to increasing bad debt due to gas price volatility (id. at 71, citing Tr. 6, at 1011-1012). The Attorney General argues that gas price volatility is not new and has continued for more than a decade (Attorney General Reply Brief at 40). He adds that the Department has previously considered this rationale when it implemented the current CGA bad debt recovery method that does not allow dollar-for-dollar recovery (Attorney General Brief at 71; Attorney General Reply Brief at 40, citing D.T.E. 02-24/25, at 172 (2002); D.T.E. 03-40, at 267 (2003)).

The Attorney General claims that during the time when the Department allowed Boston Gas to recover dollar for dollar its CGA related bad debt, Boston Gas over-recovered its bad debt costs for five of the seven years when it operated under the Department's directive in

D.P.U. 96-50 (Attorney General Reply Brief at 40, citing Exh. DTE-KED-1-1). The Attorney General contends that reversal of the current policy could produce undesirable results that would require customers to pay more than what is just and reasonable at a time when the burden on customers is greatest (Attorney General Reply Brief at 40-41).

b. KeySpan

KeySpan recommends that the Department approves Bay State's proposal to continue recovering gas cost-related bad debt expense on a reconciling basis through the CGA (KeySpan Brief at 10). KeySpan notes that such approval would re-establish the Department's "traditional" ratemaking policy, allowing the recovery of actual gas cost-related bad debt on a reconciling basis, and signal a policy change that would be applicable to all gas companies (KeySpan Brief at 15). KeySpan claims that the Department's decision in D.T.E. 02-24/25 to eliminate the reconciliation of gas cost-related bad debt runs contrary to the Department's findings in D.P.U. 96-50 that gas related bad debt expense should be reconciled because of variations in actual gas related bad debt making it difficult to set a reasonable or representative amount in rates (KeySpan Brief at 10, citing D.T.E. 02-24/25, at 171-172).

KeySpan notes that in D.T.E. 02-24/25, the Department anticipated that bad debt expense would decrease and that the intent was to avoid the recovery of bad debt expense greater than the level determined to be reasonable in a rate case (KeySpan Brief at 10, citing D.T.E. 02-24/25, at 171). KeySpan, however, claims that gas-cost-related bad debt has fluctuated and significantly increased, noting that from 2002 to 2005, for example, Boston Gas' gas costs have more than doubled, with gas cost-related bad debt expense projected to be

approximately $15 million in 2005 compared to the approximately $5 million allowed for recovery to Boston Gas under D.T.E. 03-40 (KeySpan Brief at 11-12). KeySpan claims that the bad debt recovery mechanism adopted in D.T.E. 03-40 has resulted in substantial under-recoveries of gas cost-related bad debt (id. at 14).

KeySpan claims that the Department's decision in D.T.E. 02-24/25 and D.T.E. 03-40 has decoupled bad debt expense from gas cost revenues that drive such expense level, causing substantial losses from an area where the company has no ability to control gas prices and limited ability to control the related bad debt write-offs (id. at 12). KeySpan contends that this undermined the financial operations of gas companies that would require frequent base rate adjustments regardless of whether a company is operating under a PBR plan (id. at 13-14). KeySpan adds that by eliminating the reconciling mechanism and fixing the total allowable bad debt expense in D.T.E. 02-24/25 and D.T.E. 03-40, the Department does not create the incentive sought by the Department as a basis in reversing its prior ratemaking policy (id. at 13). KeySpan states that under a PBR mechanism, gas companies are under extreme pressure to control the costs associated with bad debt and to make every effort to collect overdue amounts making no distinction between gas cost-related bad debt and distribution-related bad debt (id.).

KeySpan states that approval of Bay State's proposal would not require a base rate proceeding in order to apply the Department's policy decision to Boston Gas, noting that the bad debt expense associated with distribution revenues and recovered through base rates is fixed until base rates are reset in a future base rate proceeding (id. at 16). KeySpan states that

it will not propose to change this amount (id.). KeySpan states that, instead, it will propose only to change the amount of gas cost-related bad debt recoveries allowed through Boston Gas' CGA, a change which it claims to be within the Department's discretion to implement (id.).

KeySpan adds that following approval of Bay State's proposal, KeySpan plans to submit a company-specific filing for Boston Gas, proposing that the amount of gas cost-related bad debt allowed to be recovered through the CGA be reconciled based on the level of Boston Gas' actual gas cost-related bad debt expense (id. at 17). In addition, KeySpan states that Boston Gas has accumulated under-recovered gas cost-related bad debt expense since the Department's rate decision on October 31, 2003 in D.T.E. 03-40, and is considering two alternatives to pursue in collecting the unrecovered amount: (1) recovery through Boston Gas' CGA, which it claims would not constitute retroactive ratemaking; and (2) recovery under Boston Gas' PBR plan approved in D.T.E. 03-40 as an exogenous component that also would not constitute retroactive ratemaking (id. at 16-17).[110]

c. Company

The Company claims that its rate design proposal to collect a portion of bad debt allowance to be recovered through the base rates and the gas related portion through the CGA is consistent with Department precedent (Company Brief at 99-100, citing D.T.E. 02-24/25,

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[110] As part of its September 16, 2005 second annual PBR compliance filing, Boston Gas proposed to collect under-recoveries of gas related bad debt expense as an exogenous cost. The Department allowed the exogenous cost adjustment (Alternative 1 of Boston Gas' proposal) to recover gas related bad debt until such time as the Department provides for a consistent rule concerning bad debt cost recovery in the instant docket. Boston Gas Company, D.T.E. 05-66, at 16 (2005).

at 172; D.T.E. 03-40, at 267). The Company also claims that the Attorney General and KeySpan agree with such an allocation of total uncollectible expense for recovery between base distribution rates and the CGA (Company Brief at 100, citing Attorney General Brief at 69; Exh. KED-NE-2, at 2).

Regarding the method of recovery for gas cost-related bad debt, the Company claims that current gas price volatility and the need to capture the impact of such volatility on bad debt associated with gas costs are the same reasons that existed in the late 1990s used to justify the recovery of bad debt in the CGA (Company Brief at 100). The Company reasons that, although such price volatility has been in existence and has been previously considered by the Department, the Company was not referring to the novelty of gas price volatility but instead to the relative impact of such price volatility (Company Reply Brief at 56). Because prices of gas have increased over the years, Bay State claims that, based on residential sales alone, a 32 percent change in gas cost during the test year results in $745,560 of bad debt expenses (id., citing Exh. BSG/JAF-1). In comparison, the same 32 percent change in gas costs occurring in 1992 and 1999 would have resulted in bad debt expenses of only $136,344 and $145,267, respectively (id., citing Exh. BSG/JAF-1).

The Company states that in the mid-1990s, Bay State, along with other LDCs, unbundled its bad debt expense in order to recover bad debt associated with gas costs based on and reconciled to actual bad debt expense (Company Reply Brief at 57). The Company contends that given the current market conditions and the volatile price of gas, it is appropriate for the Department to permit Bay State to continue recovering a reasonably accurate level of

bad debt associated with gas costs (id.). The Company asserts that its current method of recovery is reasonable because under extreme price swings, deviations from actual costs would not unduly impair LDCs earnings and at the same time provide more accurate price signals to ratepayers (id.). In addition, if current gas prices decline and the associated bad debt costs also decline, such change would not be reflected in rates without the current method of recovery given the Company's PBR price cap mechanism (id.).

Noting the earnings erosion that arises from the recovery mechanism for gas cost-related bad debt established in D.T.E. 02-24/25 and D.T.E. 03-40, the Company criticizes the Attorney General's insistence on such a method of recovery and for being unmindful of the companies' requests to confirm for them mechanisms similar to what Bay State is currently using (id.). The Company emphasizes that bad debt is a direct function of the commodity costs of gas that is outside the control of the LDCs (id.). The Company claims that it has demonstrated its active and successful pursuit of bad debt recovery that inure to the benefit of ratepayers (id. at 58). Bay State concludes that no other mechanism should be imposed on the Company and that the Department accepts its current method of recovery of gas cost-related bad debt (id.).

Regarding its unregulated EP&S business, the Company claims that its operations provide ratepayers benefits including a significant contribution to O&M revenues (Company Brief at 100). The Company claims that bad debt expense is a legitimate cost of EP&S (id. at 101). The Company asserts that the Attorney General has provided no basis for removal of

the EP&S bad debt allowance, claiming that he only asserts, without support, that the associated bad debt ratio is higher than the bad debt ratio for the regulated operations (id.).

The Company claims that controlling write-offs for both gas accounts and EP&S operations has been a key element in its efforts to avoid filing for a general rate case for 13 years, except for a settlement base rate increase of $3.4 million in the late 1990s (Exh. DTE-9-23). The Company states that aside from pursuing policies for granting services and collecting amounts owed consistent with Department regulations and other laws, it: (1) avoids initial fraudulent applications for service; (2) provides effective training for call center representatives; and (3) expands the options available to customers to make payments (Exhs. DTE-9-23; DTE-18-2; AG-22-13).

3. Analysis and Findings

a. Allowable Amount of Uncollectible Expense

The Department permits companies to include for ratemaking purposes a representative level of uncollectible revenues as an expense in cost of service. D.T.E. 03-40, at 264; D.T.E. 02-24/25, at 168; D.P.U. 96-50 (Phase I) at 70; The Berkshire Gas Company, D.P.U. 92-210, at 60, 63 (1993). To determine the amount of uncollectible revenues to be included as an expense in cost of service, a company first calculates the average of the most recent consecutive three years' net write-offs, as a percentage of total firm billed revenues for the corresponding years (i.e., the uncollectible ratio), and then applies this uncollectible ratio on the test year normalized total firm sales revenues. D.T.E. 03-40, at 264-266; D.T.E. 02-24/25, at 168; D.T.E. 01-56, at 96-97; Western Massachusetts Electric Company,

D.P.U. 84-25, at 113-114 (1984). The Department finds that the Company's method for calculating its uncollectible ratio of 2.15 percent and applying such a ratio on its test year normalized total firm revenues to determine the $10,219,447 uncollectible expense comports with Department precedent.

The Attorney General has questioned the appropriateness of the Company's proposal to further increase its allowable bad debt expense equal to the product of the uncollectible ratio and the proposed increase in revenue requirement. In the past, the Department has found that it is reasonable to apply the historic percentage of uncollectibles to the revenue requirement approved in a rate case. The Berkshire Gas Company, D.P.U. 90-121, at 97 (1990), citing Massachusetts-American Water Company, D.P.U. 88-172, at 36-37 (1989). More specifically, the Department stated that the company's uncollectible expense associated with its proposed rate increase will be determined by multiplying the allowed revenue requirement increase by the uncollectible ratio. D.P.U. 90-121, at 97. Accordingly, the Department finds that the Company's proposal for an additional uncollectible expense equal to the product of its uncollectible ratio and the increase in revenue requirement approved in this Order is consistent with Department precedent. D.T.E. 98-51, at 48 (1998); D.P.U. 90-121, at 97 (1990); D.P.U. 88-172, at 36-37 (1989).[111]

Based on these findings, the Department approves a total uncollectible expense of $10,219,447 for the test year level of net write-offs and an uncollectible ratio of 2.15 percent.

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[111] In D.T.E. 03-40, the Department did not specifically address this issue in its Order. However, such an adjustment was approved and included in the total bad debt expense adjustment. D.T.E. 03-40, Sch. 2, at 513.

This amount was reduced by $7,058,572, representing the portion of the total allowable bad debt expense to be collected through the CGAC. The remaining amount of $3,160,875 (=$10,219,447 - $7,058,572) will be recovered through the Company's base distribution rates. Because the test year distribution related bad debt was $3,199,694, the Company reduced its distribution-related bad debt expense by $38,919. In addition, the Department approves an additional uncollectible expense associated with the revenue requirement increase approved in this proceeding.

Regarding the proposed $246,232 adjustment in uncollectible expense associated with the Company's unregulated EP&S business, the record shows that the Company calculated the proposed adjustment by calculating the most recent three-year average net write-offs or uncollectible ratio, applied that ratio to the test year normalized EP&S revenue, and reduced the result by the booked test year EP&S related bad debt expense. The Department finds that this method is consistent with Department precedent. D.T.E. 03-40, at 264-266; D.T.E. 02-24/25, at 168.

Regarding the Attorney General's criticism that the uncollectible ratio associated with the Company's EP&S business is relatively high compared to that of the regulated business, the Department notes that the Company provided the monthly bad debt from 2002 to 2004 for the Brockton, Lawrence, and Springfield divisions, and for each division provided the amounts of monthly bad debt by type of service (Exh. BSG/JES-1, Workpaper JES-6, at 22).[112]

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[112] In addition, the record shows that the Company maintains separate reserves for uncollectibles in its books for each type of service (Exh. DTE-9-14).

Although the EP&S percentage of annual net write-offs relative to total revenues rose from 1.90 percent and 1.85 percent in 2000 and 2001, respectively, to an average of 4.54 percent from 2002 to 2004, the record does not support the Attorney General's claim that such an increase represents imprudent operations.[113] In addition, the Department notes that the Company's EP&S operations contributed $5.7 million of profit during the test year that directly offsets expenses that would otherwise be borne by Bay State's ratepayers (Exh. BSG/SHB-1, at 58). Accordingly, the Department approves the proposed $246,232 EP&S-related uncollectible expense adjustment.

b. Recovery of Uncollectible Expense Through Base Rates and CGA

There are two related issues that the Department addresses here. The first is the apportionment of the total allowable uncollectible expense for recovery between base distribution rates and the CGA. Once the portion of the total uncollectible expense to be recovered in base distribution rates has been determined, that amount remains fixed until a company's next rate case. D.P.U. 96-50, at 73; D.T.E. 03-40, at 268. The second and more pressing issue, in the light of current developments in the wholesale market for gas supplies, relates to the appropriate manner in which the Company recovers through its CGA the bad debt expense associated with gas related costs.

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[113] From 1994 through 2004, the annual EP&S write-offs as percent of revenues fluctuated from 0.79 percent in 1995 to 3.89 percent and 4.23 percent in 1997 and 1998, respectively, and from 1.85 percent in 2001 to 4.07 percent, 5.38 percent, and 4.20 percent in 2002, 2003, and 2004, respectively (Exhs. DTE-9-13 (Supp.); BSG/JES-1, Sch. JES-6, at 10 (Rev.)).

Regarding the first issue, the Department has found that allocating bad debt expense between base distribution rates and the CGA is necessary to account for customer migration to transportation service. D.P.U. 96-50, at 72. The Department has affirmed this policy in succeeding Orders. See D.T.E. 01-56, at 96; D.T.E. 02-24/25, at 171; D.T.E. 03-40, at 266. The Department added that such an allocation is consistent with the goal of rate unbundling. D.T.E. 96-50, at 72.[114]

The Company performed unbundled allocated cost of service studies that assign costs to different rate classes (Exh. BSG/JLH-2). One of those cost items is bad debt expense (Account 904). The Company stated that, although bad debt expense was considered in the past as customer-related, in an unbundled cost of service study such an expense item must be segregated between delivery and gas supply functions (Exh. BSG/JLH-2, at 23). Thus, the Company used customer-related allocators to allocate bad debt expense among rate classes and further allocated those costs between the delivery and gas supply functions on the basis of their respective revenue requirements (id. at 23-24, Sch. JLH-2-2, at 12-1; JLH-2-3, at 12-1).

Base distribution rates are set and fixed during a traditional base rate proceeding based on an historical test year level of O&M expenses, adjusted for known and measurable changes,

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[114] On July 18, 1997, the Department directed all the investor-owned LDCs to initiate an industry-wide collaborative process designed to develop a common set of principles and procedures for the comprehensive unbundling of LDCs' distribution services. Terms and Conditions for Unbundled Gas Distribution and Supplier Service, D.T.E. 98-32-A (1998). The Department stated that it envisions a fully competitive gas industry in which all customers would have the option to purchase both gas commodity and transportation capacity from a wide range of providers operating in a competitive market. Unbundling of All Natural Gas Local Distribution Companies' Services, D.T.E. 98-32-B at 58 (1999).

and return on plant investment. Thus, a utility company would have the incentive to further improve the efficiency of its operations after the base distribution rates have been established in order to reduce costs and generate savings. A company could generate savings for its shareholders to the extent that the company can reduce distribution-related bad debt below such fixed amount during its post test year operations. Therefore, under traditional Department ratemaking policy there is an incentive for a company to minimize and reduce bad debt expense. The Department finds that the Company's method of allocating total uncollectible expense for recovery between base distribution rates and the CGA is consistent with Department precedent. D.T.E. 03-40, at 266; D.T.E. 02-24/25, at 171; D.T.E. 01-56, at 96-97; D.T.E. 96-50 (Phase I) at 72.

On the second issue, relating to the appropriate manner in which the Company recovers through the CGA the bad debt expense associated with gas related costs, the Department anticipated that as customers migrated to competitive supply, production-related bad debt would decrease because the supplier of such customers would be responsible for their bad debt. D.T.E. 02-24/25, at 171; D.T.E. 03-40, at 266. The Department stated that its intent was not to allow recovery of bad debt expense greater than the level determined to be reasonable in a rate case. D.T.E.02-24/25, at 171. See also D.T.E. 03-40, at 267. The Department added that its policy of allowing gas companies to collect a portion of bad debt through the CGA was not intended to allow dollar-for-dollar recovery of gas cost-related bad debt expense. D.T.E. 02-24/25, at 171-172; D.T.E. 03-40, at 266.

The ensuing turn of events, however, did not prove to be as expected. In the case of Bay State, for example, the average number of residential transportation customers per month decreased from 20,500 in 1998 to 45 in 2004 (Exh. AG-1-2(8), Annual Return to the Department at 43A). For non-residential transportation customers, the corresponding average number of customers per month decreased from 5,764 in 1998 to 3,208 in 2004 (Exh. AG-1-2(8), Annual Return to the Department at 43A).[115]

During the same period, the Company's total firm billed revenues increased from $279.1 million in 1998 to $473.5 million in 2004 (Exhs. DTE-9-5 (Supp.); BSG/JES-1, Sch. JES-6, at 9). Although the annual percentage net write-offs relative to total firm billed revenues remained relatively constant over the 1998 through 2004 period, the corresponding total annual net write-offs increased from $4.9 million in 1998 to $9.1 million in 2004 (Exh. DTE 9-18 (Supp.) at 2).[116] Under its current bad debt recovery mechanism approved in D.T.E. 97-97, Bay State recovered through the CGAC $2.6 million, or 52 percent, of the $4.9 million net write-offs in 1998 (id.). In 2004, Bay State recovered through the CGAC $6.2 million, or 68 percent, of the $9.1 million net write-offs in 2004 (id.).

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[115] The average number of residential transportation customers for the intervening years were: 16,935 in 1999, 10,885 in 2000, 715 in 2001, 22 in 2002, and 39 in 2003 (Exh. AG 1-2 (Bulk), Annual Returns to the Department at 43A). For the non-residential transportation customers, the average number per month were: 7,097 in 1999, 6,134 in 2000, 5,382 in 2001, 4,138 in 2002, and 3,439 in 2003 (id.).

[116] The annual percentage net write-offs relative to total firm billed revenues were 1.76 percent in 1998, 1.66 percent in 1999, 1.64 percent in 2000, 2.00 percent in 2001, 2.39 percent in 2002, 2.22 percent in 2003, and 1.92 percent in 2004 (Exhs. DTE 9-5 (Supp.); BSG/JES-1, Sch. JES-6, at 9 [Rev. 1]).

In the case of Boston Gas, the record shows that its total firm billed revenues were $640.8 million in 1997 and $993.5 million in 2004 (Exh. DTE-KED-1-1 (Rev.)). Boston Gas' total net write-offs correspondingly increased from $12.9 million in 1997 to $21.9 million in 2004 (id.). From 1997 through October of 2003, Boston Gas recovered gas cost-related bad debt expense through the CGA in a manner specified in D.P.U. 96-50. More specifically, from 1997 through October of 2003, Boston Gas recovered 62 percent of its annual net write-offs through the CGA, with a fixed amount of $4.9 million of uncollectible expense embedded in its base distribution rates (id.). Assuming that Boston Gas fully recovered annually that $4.9 million of bad debt expense embedded in its base distribution rates, then Boston Gas would have over-recovered its actual net write-offs for years 1997 through 2001 by a cumulative amount of $3.0 million and under-recovered in 2002 and 2003 by a total of $2.0 million[117] for a total cumulative over-recovery of $0.9 million during the 1997 through 2003 period (id.). However, after implementing the D.T.E. 03-40 method of bad debt recovery that was initially approved in D.T.E. 02-24/25, and assuming that the company would have fully recovered the $4.2 million bad debt embedded in its base distribution rates effective in November 2003, then Boston Gas would have had a total bad debt under-recovery of $14.4 million for 2004 alone (id.).[118]

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[117] A portion of the under-recovery for 2003 would have been attributable to the revised method of bad debt recovery in D.T.E. 03-40, where the Order was issued on October 31, 2003.

[118] Similarly, had the D.T.E. 02-24/25 method of bad debt recovery been applied to Bay State, and assuming that its total bad debt expense allowed in a hypothetical base rate

(continued…)

Conversely, if the market price of gas supply declines from its historical levels after bad debt expense has been set for a utility during a base rate proceeding, then actual post test year net write-offs could correspondingly fall and the utility could have a significant windfall. More specifically, if, for example, Boston Gas' 2004 actual net write-off of $21.9 million were the approved bad debt expense during a base rate proceeding and prices decline to the 1997 levels during the following year such that actual net write-offs were $12.9 million, then the Company could have a windfall of approximately $9.0 million.[119]

Thus, in a market condition characterized by price volatility, fixing the total amount of uncollectible expense that could be recovered as part of a base rate proceeding could have a significant effect on a company's earnings and could violate the Department's rate structure goal of earnings stability. The Department has defined earnings stability to mean that the amount a company earns from its rates should not vary significantly over a period of one or two years. D.T.E. 03-40, at 366, citing D.T.E. 01-56, at 135; D.T.E. 02-24/25, at 252-253. Accordingly, based on a review of this record, the Department finds that the ratemaking treatment and recovery method for gas cost-related bad debt expense established in

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118 (…continued)
proceeding in 1998 was its net write-offs of $4.9 million for that year, then Bay State would have recovered only approximately one-half of its 2004 actual net write-offs, producing an under-recovery of $4.2 million for 2004 alone.

119 The Department notes that despite the increases in Boston Gas' annual firm billed revenues, its firm billed therms remained relatively stable from 118.6 million therms in 1997 to 120.3 million therms in 2004, or an increase of 1.4 percent over the seven-year period (Exh. DTE-KED-1-1). The Department also notes that the indicated amounts of Boston Gas' over- or under-recovered uncollectible expense are solely for illustration in arriving at a consistent rule and not intended for any ratemaking purposes.

D.T.E. 02-24/25 and affirmed in D.T.E. 03-40 no longer achieve the Department's rate structure goal of earnings stability.

As noted above, the Department allowed Boston Gas to recover under-recovered bad debt expense as an exogenous cost until such time that the Department provides for a consistent rule concerning bad debt recovery. Boston Gas Company, D.T.E. 05-66, at 16 (2005). In granting Boston Gas' requested relief for its large and significant amount of unrecovered uncollectible expense as a result of the method of bad debt recovery established in D.T.E. 02-24/25 and applied to Boston Gas in D.T.E. 03-40, the Department took note of the current, historically extreme wholesale gas prices and the unforeseen and unintended effects of such a method on gas-related bad debt expense recovery. Id. Recognizing that Boston Gas' petition in D.T.E. 05-66 is a matter that is at issue in the instant docket, the Department stated that it would allow such a relief to Boston Gas only until such time as the Department provides for a consistent rule concerning CGAC bad debt cost recovery. Id. We address this matter below.

Allocating a fixed amount of the total allowable uncollectible expense for recovery through the base distribution rates does not guarantee that the Company will recover that amount dollar for dollar. As noted above, to the extent that the Company can minimize its actual net write-offs post test year or increase its delivery throughput, then the Company could generate savings for its shareholders. (There is, of course, incentive to manage slow-paying or non-paying accounts so as to minimize losses from uncollectible distribution charges. That incentive also has a likely effect on managing gas commodity cost collection, too.) Thus,

although dollar-for-dollar recovery is not guaranteed, the incentive to reduce bad debt is preserved. Therefore, for the fixed amount of total uncollectible expense allocated to the base distribution rates, the Company has the incentive to minimize bad debt expense.

For the portion of the total uncollectible expense that is gas cost-related and determined to be reasonable in the instant case, the record shows that there are factors outside of the Company's control that could result in the level of actual post test year net write-offs to deviate from that level initially determined to be reasonable (Exh. DTE-KED-1-1 (Rev.)). Therefore, requiring the Company to reconcile CGA bad debt recovery to that initially-determined amount could result in over- or under-collections that depend on the vagaries of the ensuing market conditions. In turn, such over- or under-collections could – and, over time, likely would – adversely affect the Company's earning stability, financial integrity, and its ability to attract capital. D.T.E. 05-66, at 15. Financial instability of this kind threatens customers' interest in receiving quality service, as well.

In D.T.E. 02-24/25, the Department noted that Fitchburg is able to track its bad debt accounts by specific billing components. D.T.E. 02-24/25, at 164, n.64. Similarly, in D.T.E. 03-40, the Department noted that Boston Gas could track actual monthly write-offs into gas cost and base rates components. D.T.E. 03-40, at 266-267. This more accurate tracking and collection of gas cost-related bad debt through the CGA could avoid potential under- or over-collections and help preserve the Company's financial integrity.[120] In addition, because

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[120] In Investigation into Advanced Metering, D.T.E. 01-28 (Phase II) at 15 (2001)), the Department addressed partial payments to competitive suppliers. The Department

(continued…)

uncollectible expense is a component of the cost of providing service, such a method provides more accurate price signals to ratepayers. The Department finds that such a precise method for tracking and recovery of gas cost-related bad debt is consistent with the Department's rate structure goal of earnings stability and efficiency. D.T.E. 03-40, at 365; D.T.E. 01-56, at 135; D.T.E. 02-24/25, at 252; D.P.U. 92-78, at 116 (1992); D.P.U. 89-81, at 50 (1989).

c. Recovery of Gas Cost-Related Bad Debt

(i). Current Method

Bay State proposed to continue to apply its current method of recovery for gas cost-related bad debt (Exhs. BSG/JAF-3, at 12-13; BSG/JAF-3-1). The Company defined bad debt expense in its current CGAC tariff as uncollectible expense attributed to the Company's gas costs (M.D.T.E. No. 3, § 6.05(2) at 2). The Company currently files peak and off-peak gas adjustment factors ("GAF") computed on a semi-annual basis using forecast gas costs, carrying charges, sendout volumes, and sales volumes that are weather-normalized (M.D.T.E. No. 3, § 6.06, at 4). Both the peak and off-peak GAF formulae include a bad debt factor computed on a per therm basis billed to Bay State's ratepayers (M.D.T.E. No. 3, § 6.06, at 9, 13).

The current CGAC tariff provides for peak and off-peak reconciliations for uncollected gas-cost-related bad debt during the peak and off-peak seasons, respectively (M.D.T.E. No. 3,

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[120] (…continued)
addressed a similar concern in D.T.E. 02-24/25, at 172, n.66, and directed the company to allocate partial payments between distribution and gas-related bad debt recoveries consistent with D.T.E. 01-28. We direct the Company to also allocate partial payments between CGA and distribution service in like manner.

§ 6.09(1)(e),(f) at 16).[121] In its September 15, 2005 peak GAF filing, for example, using annual forecasts, the Company derives its bad debt write-offs for the upcoming months of November through April of the following year and divides the estimated amount by the forecast firm sales volume for the same six-month period to arrive at the peak GAF (Bay State's Cost of Gas Adjustment - Peak Period Adjustment factors for the Period November 2005 through April 2006, dated September 15, 2005, § 8).

The Company calculates the bad debt write-offs for the coming six months by: (1) multiplying its annual gas costs forecast by an uncollectible ratio of 1.7 percent;[122] and (2) adding to this amount to the bad debt balance as of the last month of the preceding off-peak season (October), plus estimated amounts for the associated working capital allowance and carrying charges (id.).

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[121] The peak or off-peak bad debt reconciliation adjustments ("Rapbd" - Account 175.21 balance, and "Raopbd" - Account 175.11, respectively) are included in the peak GAF or off-peak GAF calculations that incorporate the peak or off-peak bad debt balance as of the peak or off-peak reconciliation dates, respectively (M.D.T.E. No. 3, § 6.09, at 17).

[122] In D.T.E. 97-97, the Department approved a settlement that provided, among other things, the transfer of $2.7 million in bad debt expense associated with purchased gas costs from base rates to the CGAC. D.T.E. 97-97, at 3. The Department stated that "[t]hese costs would be reconciled on a semi-annual basis . . . . The Company contended that the proposal to transfer a portion of bad debt expenses to the CGAC is consistent with Boston Gas Company, D.P.U. 96-50 (Phase I) (1996) . . . ." Id. at 3. In its March 24, 1998 Off-Peak GAF filing, Bay State noted the bad debt annualized amount of $2.7 million excluded from base rates in D.T.E. 97-97 and that "[b]ad [d]ebt expense as a percent of revenues from firm sales customers = 1.7%." The same bad debt ratio has been used by Bay State in its succeeding GAF filings through 2005.

The Company's actual percentage write-offs is equal to the 12-month rolling average calculated by dividing gas revenues by total firm sales and transportation revenues (id.). The Company applies this percentage on the actual total Company monthly write-offs to determine the actual gas cost-related bad debt for that month, which serves as the basis for seasonal reconciliation (id.). The same method is followed for the off-peak season.

(ii). Proposed Method

The Company filed its proposed CGAC tariff, M.D.T.E. No. 36, indicating certain changes in such revised tariff (Exhs. BSG/JAF-3, at 12-13; BSG/JAF-3-1, M.D.T.E. No. 36). Although the Company maintained in its proposed CGAC tariff the existing seasonal GAFs, the Company eliminated the peak and off-peak bad debt factors as components of the GAFs (Exh. BSG/JAF-3-1, at 12-13; Tr. 13, at 2215-2217; Tr. 13, at 2234). Instead, the Company proposed to simplify its calculation and reconciliation of bad debt (Tr. 13, 2234).

More specifically, instead of having specific bad debt factors that are applicable to the peak and off-peak season as specified in the existing tariff, the proposed CGAC tariff uses a bad debt factor ("BDF") formula that determines the per therm charge associated with bad debt that is updated on a seasonal basis (Exh. BSG/JAF-3-1, at 33; RR-DTE-172, at 20). The component of this formula includes the sum of the following three items divided by the forecast of annual sales: (1) the bad debt expense derived by multiplying the forecast annual gas costs by the uncollectible ratio determined in the instant docket; (2) bad debt reconciliation adjustment; and (3) bad debt allowable working capital (RR-DTE-172, at 20).

In the initially-filed CGAC tariff, the proposed bad debt formula included an interest component defined as "interest on total bad debt allowance" (Exh. JAF-3-1, at 34). During the proceeding, the Company admitted that such an interest component was misplaced and therefore should be deleted from the bad debt formula (Tr. 13, at 2238-2239; RR-AG-66). Accordingly, the Company revised its proposed CGAC tariff to incorporate such a change as well as other modifications identified during the proceeding (RR-DTE-172, at 19).

The Department finds that the Company's proposed CGAC tariff provisions, as modified, relating to the recovery of its gas cost-related bad debt are consistent with the above finding on the appropriate method of recovery for such cost. The Department approves the Company's proposed and updated gas cost bad debt recovery mechanism as shown in Record Request DTE-172.[123] As noted, this method allows the Company to collect and recover its gas cost-related bad debt on a reconciling basis. However, this method uses an approximation similar to the method approved in D.P.U. 96-50 and, therefore, does not meet the standard of precision required by the Department in this proceeding. Accordingly, the Department directs the Company to implement such a precise tracking for and recovery of gas cost-related bad debt on or before its 2006 peak season GAF filing. In the interim, the Company shall use the

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[123] The Department notes that page 8 of 21 of the revised CGAC tariff indicates: "a bad debt factor (BDF), defined in Section 16.00 . . . ." (RR-DTE-172, at 8). The BDF is defined in Section 15.00 (id. at 19). In addition, the caption for Section 15.03 is misspelled (id. at 20). The Department directs the Company in its compliance filing to this Order to make the necessary changes and provide a red-lined strike out version of the CGAC tariff.

method of gas cost-related bad debt recovery and reconciliation as provided for in its approved CGAC tariff.

KeySpan proposed on brief that it would submit a company- specific filing for Boston Gas assuming Department approval of Bay State's bad debt recovery method (KeySpan Brief at 17). This Order provides KeySpan with the guidance necessary to submit a revised CGAC filing, effective January 1, 2006.

J. Amortization of Deferred Farm Discount

1. Introduction

Pursuant to the Electric Restructuring Act, St. 1997, c. 164, § 315 ("Restructuring Act" or "Act"), Bay State has provided certain gas customers engaged in agriculture or farming an additional ten percent reduction in the rates to which such customers would otherwise be subject ("farm discount") (Exh. BSG/JES-1, at 32-33). In Farm Discounts, D.T.E. 98-47, at 6 (Letter Order) (November 16, 1998), the Department stated that, with regard to recovery of the farm discount, gas distribution companies may defer costs associated with the implementation of the farm discount for consideration in a subsequent general rate case. Bay State is seeking recovery of $76,600 related to the farm discount, which includes the discount that has been provided from 2002 through the end of the test year (Exh. BSG/JES-1, at 33, citing Exh. BSG/JES-1, Sch. JES-6, at 13 (Rev.)). The Company is proposing to amortize this amount over five years, consistent with the duration of its proposed PBR plan (Exh. BSG/JES-1, at 33). This proposal results in a pro forma adjustment to Bay

State's test year revenue requirement of $15,320 (id.). No party commented on the Company's proposal.

2. Analysis and Findings

Consistent with precedent, the Department finds that Bay State is allowed to recover the amount of the farm discount credit that it is seeking in this proceeding. See D.T.E. 02-24/25, at 203-205. In addition, the Department directs the Company to amortize this amount over ten years, because ten years is the expected time period before the Company's next distribution rate change. Accordingly, the Department will reduce the Company's proposed cost of service by $7,660.

K. Postage Expense

1. Introduction

During the test year, Bay State booked $1,255,946 in postage expense (Exh. BSG/JES-1, at 33-34). The Company states that on April 8, 2005, the United States Postal Service ("USPS") filed a request seeking an across-the-board rate increase of 5.4 percent which, inter alia, will increase the cost of first-class mail from $0.37 to $0.39 (Exhs. BSG/JES-1, at 34; DTE 14-2). According to Bay State, the USPS seeks to have the rate increase take effect in early 2006 (Exh. BSG/JES-1 at 34).

In order to incorporate the effects of the proposed USPS rate increase on its postage expense, Bay State applied the proposed increase in first-class postage from $0.37 to $0.39, producing an overall increase of 5.41 percent (Exh. BSG/JES-1, Sch. JES-6, at 14 (Rev.)). The Company then multiplied its calculated 5.41 percent increase by test year postage expense

of $1,255,946, thereby producing an increase of $67,947 and a proposed postage expense of $1,323,893 (Exh. BSG/JES-1 at 34, Schs. JES-6, at 14 (Rev.); JES-6 (Rev. 1) at 1(a)).[124]

2. Positions of Parties

a. Attorney General

The Attorney General states that the Company's proposed postage increase is inappropriate and should be denied (Attorney General Reply Brief at 34). The Attorney General notes that the Department has consistently based allowed rates on test year data, adjusted for known and measurable changes (Attorney General Reply Brief at 34, citing D.T.E. 02-24/25, at 76, 195; Eastern Edison Company, D.P.U. 1580, at 13-17 (1984)). The Attorney General maintained that, as of the dates of hearings, briefs , and reply briefs, the USPS had not yet confirmed the requested increase, the Company's proposed increase. Therefore, the Attorney General stated that the increase was not known and measurable and should therefore be denied from the cost of service (id., citing Exh. UWUA 3-20; Tr. 3, at 525-526; D.T.E. 03-40, at 132).

b. Local 273

Local 273 argued that the Company's proposed postage increase should be denied because it was not known and measurable by the time of reply briefs (UWUA Reply Brief at 12-13). Local 273 noted that the Company's proposal was based on a USPS press release

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[124] The Company stated that if a different level of increase was approved by the Postal Rate Commission before the close of the record in this proceeding, then it would update its filing for this cost of service item accordingly (Exh. DTE 6-9; Tr. 3, at 550).

and related news article (id., citing Exh. UWUA 3-20). Local 273 points out that USPS rate increases are subject to the review of the Postal Rate Commission, which may then approve, reject, or modify the request (id. at 12-13, citing 36 U.S.C. § 3624(c)(1) and (2)). Thus, Local 273 considered the Company's proposed adjustment to be speculative (UWUA Reply Brief at 13).

c. Company

Bay State asserts that a decision by the Postal Rate Commission regarding the requested increase was expected before the end of the present proceeding, and no later than the midpoint of the year (Company Brief at 107). The Company stated that the increase is required for the USPS to fund a $3.1 billion escrow requirement mandated by P.L. 108-18 (Company Reply Brief at 30, citing Exh. BSG/JES-1, Workpaper JES-6, at 30). Bay State asserts that without the requested increase in postal rates, the United States Congress would be required to adopt legislation to repeal or alter the obligation established by P.L. 108-18.[125] The Company contended that it is "more than reasonably certain" that the postal rate increase would be approved as requested (Company Reply Brief at 31). Therefore, the Company considered the requested increase to be known according to the weight of the evidence, and measurable because the amount of the increase had been announced (id.).

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[125] Strictly speaking, Congressional action on P.L. 108-18 is not dependent upon the Postal Rate Commission's decision (Exh. BSG/JES-1, Workpaper JES-6, at 30). Rather, the need for the postal rate increase is dependent upon Congressional action on P.L. 108-18.

3. Analysis and Findings

The Department recognizes postage expense as a legitimate cost of doing business. If a postal rate increase occurs prior to the issue of an Order, the increase is eligible for inclusion in cost of service as a known and measurable change to test year expense. Massachusetts-American Water Company, D.P.U. 88-172, at 23-24 (1989); Massachusetts Electric Company, D.P.U. 800, at 29-30 (1982). Here, Bay State sought approval of a postal rate increase based on the expectation that it would be approved by the Postal Rate Commission.

On November 15, 2005, the Postal Service Governors voted to accept the Postal Rate Commission's recommendations to increase most postal rates and fees effective January 8, 2006. See United States Postal Service News Release No. 05-097, http://www.usps.com/communications/news/press/2005/pr_097.htm. Therefore, the proposed increase is known and measurable. The Department finds that the requested increase in postal expense meets our standard. D.P.U. 90-121, at 118. Accordingly, the Department accepts the Company's proposed cost of service increase of $67,947 for postage expense.

L. Metscan Expense

1. Introduction

Metscan is an automated meter reading technology that was installed and in service to customers throughout the 1990s (Exh. BSG/SHB-1, at 45). Over 253,000 Metscan devices

were installed beginning in 1991 and continuing through 1998 (id. at 46).[126] However, in the late 1990s the Company was confronted with a number of factors that contributed to its decision in 2000 to switch from the Metscan technology to the Itron technology including: device longevity; continued availability of vendor support; and the continued improvements that were being made in wireless meter reading technology (id. at 47).[127] The Company decided to switch to the Itron technology because it was determined to be more cost-effective as well as being an increasingly prevalent meter reading technology that has proven itself to be superior to the Metscan technology (id. at 47-48).

In 1998, the Company entered into a series of sale/leaseback agreements with Fleet Capital Leasing for the Metscan equipment, which had terms of eleven years (Exhs. DTE 1-20; AG 3-33). The Company is seeking to recover $13,216,748 associated with: (1) the $3,121,366 undepreciated plant investment in the Metscan devices; and (2) the $10,095,382 net present value of the lease payments with Fleet Capital Leasing (Exhs. BSG/JES-3; BSG/JES-3, at 1). Bay State is proposing to amortize and recover these costs over five years, which would coincide with the Company's proposed five-year PBR proposal (Exh. BSG/SHB-1, at 45).

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126 As of December 31, 2004, the Company had 2,921 Metscan devices still in service (Exh. DTE-5-28).

127 Itron devices are wireless, radio-based meter reading equipment (Exh. BSG-SHB-1, at 48).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the amortization of the Metscan equipment should be disallowed because the equipment is redundant and is an unused asset that is not in service and, therefore, does not provide benefits to ratepayers (Attorney General Brief at 87; Attorney General Reply Brief at 38). The Attorney General states that if the Department were to allow the Company to collect for the Metscan devices, it would be allowing the Company to engage in a double-recovery of sorts because Bay State replaced the Metscan devices with Itron meters, the costs of which are also included in rate base (Attorney General Brief at 90). The Attorney General asserts that ratepayers should not bear the burden of paying for substandard equipment, and concludes that the Metscan costs fail to meet the Department's used and useful standard for inclusion in rate base (id. at 91; Attorney General Reply Brief at 39).

b. Local 273

Local 273 contends that because the Metscan technology was unproven, Bay State needlessly put customers at too great a risk, and therefore acted imprudently (UWUA Brief at 66). Local 273 argues that the Company's investment in Metscan was imprudent and should be disallowed (id.). Therefore, Local 273 states that the Metscan costs should be absorbed by Bay State and not borne by ratepayers (id.).

c. Company

Bay State argues that the deployment of the Metscan equipment was prudent based on the information available to the Company at the time (Company Brief at 113; Company Reply

Brief at 18-19). The Company argues that its proposed treatment of the undepreciated portion of the Metscan costs is consistent with Department precedent regarding the treatment of abandoned plant (i.e., the Company is seeking return of, but not on, the amount amortized over a reasonable period of time) (Company Brief at 114-115). Bay State contends that the record amply demonstrates that the Metscan equipment was prudently acquired and duly in service and, therefore, used and useful to ratepayers for a decade (id. at 117; Company Reply Brief at 18).

3. Analysis and Findings

For costs to be included in rate base, the expenditures must be prudently incurred, and the resulting plant must be used and useful in providing service to ratepayers. D.T.E. 98-51, at 12; D.P.U. 93-60, at 24; D.P.U. 85-270, at 20. A prudence review must determine whether the utility's actions, based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances that then existed. D.T.E. 98-51, at 12. A determination of reasonableness and prudence may not properly be made on the basis of hindsight judgments, nor is it appropriate for the Department merely to substitute its own judgment for the judgment of the management of the utility. Attorney General v. Department of Public Utilities, 390 Mass. 208, 229 (1983). A prudence review must base its findings on how a company reasonably should have responded to the particular circumstances, and whether the company's actions were in fact prudent in light of all the circumstances that were known or reasonably should have been known at the time the decision was made. D.T.E. 98-51, at 12; D.P.U. 93-60, at 24; D.P.U. 85-270, at 23-24; D.P.U. 906, at 165. The prudence test

determines whether costs recovery is allowed at all, while the used and useful analysis determines that portion of prudently incurred costs on which the utility is entitled to earn a return. D.T.E. 98-51, at 12-13; D.P.U. 93-60, at 25; D.P.U. 85-270, at 25-27.

At the outset, the Department notes that Bay State is seeking to remove the remaining Metscan investment from rate base and, instead, amortize this amount over five years (Exh. BSG/SHB-1, at 50). Consequently, the Company is only seeking recovery of the outstanding Metscan investment, not recovery on this investment (id. at 45). Regarding the question of the Metscan equipment being used and useful to ratepayers, the evidence demonstrates that the equipment meets the used and useful standard, because the Metscan equipment was the Company's main source for meter readings for nearly a decade (id. at 47).

Regarding the question of the prudence of the original investment in the Metscan technology, the record evidence supports the conclusion that the Company was prudent in its initial deployment of the Metscan equipment (Exh. BSG/SHB-1, at 45-46; Tr. at 138-139; RR-DTE-49 (Supp.)). The Company began to deploy the Metscan devices in earnest in 1991, and it was not until 1998 that the Company began to experience an unacceptable failure rate from the Metscan equipment (Exhs. DTE-1-19; DTE-5-20; AG-3-32). In addition, the Company field tested the Metscan equipment four years prior to full deployment of the equipment (Exh. BSG/SHB-1, at 46). Clearly, the decision to deploy the Metscan equipment was made with adequate deliberation. Therefore, the Department concludes that the Company's investment in the Metscan equipment was prudent.

Regarding the Company's decision to switch from the Metscan equipment to the Itron equipment, the record evidence also supports the conclusion that Bay State's decision was a prudent one (Exhs. BSG/SHB-1, at 48; DTE-5-17; AG-3-32). The Company was faced with a system that was experiencing high failure rates, as well as diminishing technical support (Exhs. DTE-5-18; AG-3-32). As a result, the Company explored options for a more cost-effective means to read its customers' meters (Exh. AG-3-32). Therefore, the Department concludes that it was prudent for the Company to switch from the Metscan technology to the Itron technology.

Bay State's proposal for recovery of, but not on, the remaining Metscan balance is consistent with Department precedent regarding the appropriate recovery of undepreciated, prudently-incurred plant. Wylde Wood Water Works, D.P.U. 86-93 (1987); D.P.U. 85-270 (1986); Fitchburg Gas and Electric Light Company, D.P.U. 19084 (1977). In addition, the Company's proposed treatment of these costs is consistent with the Department's precedent regarding the abandonment of plant that can be considered redundant to the newly installed plant. NYNEX, D.P.U. 94-50, at 296-300 (1995); New England Telephone & Telegraph Company, D.P.U. 86-33-G at 37-44 (1989). Therefore, the Department will allow the Company to remove the relevant Metscan costs from rate base and recover them by amortizing them over a reasonable period.

The Company has proposed to amortize these costs over five years, which is the same period as Bay State's five-year PBR proposal (Exh. BSG-SHB-1, at 45). Because the Department has approved a ten-year PBR (Section IX.C.3, below), this proposed period is not

consistent with Department precedent. D.P.U. 96-50 (Phase I) at 55-56. Therefore, the Department finds that amortizing the recovery of these costs over the same ten-year period as the Company's PBR mechanism is reasonable. This produces an amortization expense of $1,321,675. Accordingly, the Department will reduce the Company's proposed cost of service by $1,321,675.

M. Itron Lease Payments

1. Introduction

Since 2000, Bay State has been changing over its automated meter reading system from Metscan equipment, which is a telephone-based system, to Itron equipment, which is a wireless, radio-based system (Exh. BSG/SHB-1, at 48). The Company engaged in a sale/leaseback agreement for a block of Itron units with a cost of approximately $2.4 million in December 2004 (Exh. BSG/JES-1, at 35). Consequently, Bay State proposed an increase to O&M expense of $310,104 to annualize the annual lease payments for these units (Exhs. BSG/JES-1, at 35; BSG/JES-1, Sch. JES-6, at 16 (Rev.)). The Company also states that it has removed the costs of these Itron units from the test year utility plant balance (Exh. BSG/JES-1, at 35). No party commented on the Company's proposal.

2. Analysis and Findings

The Department recognizes that a utility's lease expense represents an allowable cost qualified for inclusion in its overall cost of service. D.T.E. 02-24/25, at 71; D.P.U. 95-118, at 42, n.24; NYNEX Price Cap, D.P.U. 94-50, at 436 (1995); Boston Gas Company, D.P.U. 88-67 (Phase I) at 95-97 (1988); D.P.U. 85-270, at 183-187. The Department has reviewed

the proposed adjustment and is satisfied that Bay State has properly accounted for all the necessary adjustments to recognize the Itron lease for ratemaking purposes. Therefore, the Department finds the Company's proposed adjustment is appropriate and consistent with Department precedent, in that the adjustment both removes the cost of the Itron equipment from rate base and recognizes the full annual lease expense in cost of service. D.P.U. 94-50, at 436-437. Accordingly, the Company's proposed cost of service adjustment for the Itron lease is allowed.

N. Inflation Allowance

1. Introduction

Bay State proposed an inflation adjustment of $1,473,203 (Exhs. BSG/JES-1, at 38; BSG/JES-1, Sch. JES-6, at 19 [Rev. 1]). The Company used the gross domestic product implicit price deflator ("GDPIPD") to calculate the inflation allowance (Exh. BSG/JES-1, at 37). Bay State applied the GDPIPD from the midpoint of the test year to the midpoint of the rate year, which resulted in a 4.31 percent inflation factor (Exh. BSG/JES-1, Sch. JES-6, at 20 [Rev. 1]). The Company calculated the inflation adjustment by multiplying the inflation factor of 4.31 percent by its residual O&M expenses of $34,181,035, thus producing an inflation adjustment of $1,473,203 (Exh. BSG/JES-1, Sch. JES-6[Rev. 2] at 19).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Company incorrectly included various charges from NCSC and Northern Utilities, as well as property taxes associated with the Company's

Westborough building, in its residual O&M balance (Attorney General Brief at 80). The Attorney General states that the Company's NCSC charges booked to Account 923 include $762,423 in capital costs such as depreciation, income taxes, interest expense, and property taxes (id., citing Exh. AG 1-25). The Attorney General argues that similar charges from Northern Utilities booked to Account 921, totaling $190,868, were also included in the Company's residual O&M expense (id.). Finally, the Attorney General contends that the Company included property taxes associated with its Westborough building in the amount of $71,788 (id.). The Attorney General states that these costs are capital costs that are fixed and will not increase with inflation, and so should not be subject to an inflation adjustment (Attorney General Brief at 80). Therefore, the Attorney General proposes that these costs be removed from Bay State's residual O&M expense balance (id. at 80-81, citing D.P.U. 92-111, at 163; D.P.U. 84-25, at 85; Commonwealth Electric Company, D.P.U. 956, at 38 (1982); D.P.U. 906, at 71-74).

b. Company

Bay State contends that the costs allocated from its affiliates that the Attorney General characterizes as capital costs are not actually "fixed" capital costs, but rather represent costs that are subject to inflationary pressures (Company Brief at 110). The Company maintains that because these costs are not individually adjusted in any other area of its rate filing, they are appropriately included in the residual O&M expense for determining the inflation allowance (id. at 110).

3. Analysis and Findings

The inflation allowance recognizes that known inflationary pressures tend to affect a company's expenses in a manner that can be measured reasonably. D.T.E. 02-24/25, at 184; D.T.E. 01-56, at 71; D.T.E. 98-51, at 100; D.T.E. 96-50 (Phase I) at 112; D.P.U. 95-40, at 64. The inflation allowance is intended to adjust certain O&M expenses for inflation, where the expenses are heterogenous in nature and include no single expense large enough to warrant specific focus and effort in adjusting. Boston Edison Company, D.P.U. 1720, at 20-21 (1983); D.P.U. 956, at 40. The Department permits utilities to increase their test year residual O&M expense by the projected GDPIPD from the midpoint of the test year to the midpoint of the rate year. D.P.U. 95-40, at 64; D.P.U. 92-250, at 97; D.P.U. 92-78, at 60. In order for the Department to allow a utility to recover an inflation adjustment, the utility must demonstrate that it has implemented cost containment measures. D.P.U. 96-50 (Phase I) at 113.

Bay State's total payroll expense associated with operating and maintenance expense decreased by 23.6 percent between 1991 and 2004, from $30,663,232 in 1991 to $23,435,368 in 2004 (Compare D.P.U. 92-111, at 163 with Exh. BSG/JES-1, Sch. JES-6, at 19 [Rev. 1]). In addition, the Company evaluates its medical, dental, and other insurance costs on an ongoing basis in order to evaluate coverage and market alternatives (Exhs. BSG/JES-1, at 17-18; BSG/SAB-1, at 40). Accordingly, the Department finds that an inflation allowance adjustment equal to the most recent forecast of GDPIPD for the appropriate period as proposed

by Bay State, applied to the Company's approved level of residual O&M expense, is proper in this case.

Concerning the NCSC and Northern Utilities charges that the Attorney General characterizes as capital items, the expenses in question have been booked to Accounts 921 and 923 (Exh. AG 1-25). Expenses booked to these administrative and general accounts are customarily considered to be O&M expenses. Just as billings from outside vendors may include costs that are of a fixed nature to the particular vendors, the fact that NCSC and Northern Utilities include items of a capital nature in their billings to the Company does not disqualify them from consideration in the Department's inflation allowance. The Department finds that the Company's costs allocated from NCSC and Northern Utilities are appropriately considered as O&M expenses eligible for inclusion in the inflation adjustment.

Concerning the property taxes associated with Bay State's Westborough office, in its previous rate proceeding, the Company reduced residual O&M expenses by property taxes on an LNG lease in calculating the inflation allowance on its own. D.P.U. 92-111, at 163. The Department made certain adjustments to the Company's inflation allowance, shown on Schedule JES-2, but none of these adjustments involved property taxes on the lease. Consistent with the Company's own treatment of this expense in D.P.U. 92-111, the Department will exclude property taxes from residual O&M.

If an O&M expense has been adjusted or disallowed from ratemaking purposes, that expense is also removed in its entirety from the inflation allowance. D.T.E. 02-24/25, at 184; D.P.U. 01-50, at 19; D.P.U. 88-67 (Phase One) at 141; D.P.U. 87-122, at 82. The

Department has adjusted the Company's O&M expense for the corporate jet and Westborough lease. Therefore, the test year expense associated with these items, totaling $1,809,631, must be removed from Bay State's residual O&M expense calculations. As shown on Table 1, the requested inflation allowance is $1,389,313. Accordingly, the Department will reduce the Company's proposed cost of service by $83,890.

	Description	$ Amount
1	Test Year O&M Expense Per Books	99,007,484
	Less:	
2	Payroll - Union & Non-Union	23,435,368
3	Incentive Compensation	124,422
4	Pensions	2,700,563
5	PBOP	2,325,888
6	Employee Benefits All Other	3,428,461
7	Insurance Expense	2,301,379
8	Self Insurance Claims	397,749
9	Bad Debt Expense - Gas Revenue	3,199,694
10	Bad Debt Expense - EP&S	412,767
11	NiSource Corporate Services: Payroll Per Books	10,499,278
12	NiSource Corporate Services: Medical & Dental	1,231,237
13	NiSource Corporate Services: Pension Expense	482,106
14	NiSource Corporate Services: POP Expense	121,725
15	NiSource Corporate Services: Payroll / FICA	744,396
16	NiSource Corporate Services: Charitable Contributions	8,735
17	Charitable Contributions	147,271
18	Postage	1,255,946
19	Metscan Meter Reading Lease Payments	2,919,051
20	CGA & LDAC Recoverable Costs	9,227,167
21	Total Test Year Amounts (Lines 2 thru 20)	64,963,203
22	Proposed Residual O&M Expenses Subject to Inflation (Line 1 Minus Line 21)	34,044,281
23	Removal of Westboro Lease and Corporate Jet expenses (including associated property taxes)	1,809,631
24	Residual O&M Expenses Subject to Inflation (Line 22 Minus Line 23)	32,234,650
25	Increase in GDPIPD from Midpoint of the Test Year to the Midpoint of the Rate Year	4.31%
26	Total Inflation Adjustment	1,389,313

O. Advertising and Promotion Expense

1. Introduction

During the test year, the Company reported that it booked $240,545 in direct advertising, marketing and sales promotion expenses to utility operations (Exh. MOC 1-3; Tr. 5, at 818). The Company determined this expense by taking its total direct advertising, marketing and sales promotion expense of $310,266 and subtracting $40,573 booked below-the-line and $29,148 billed to Northern Utilities through a service agreement with the Company (Exh. MOC 1-3; Tr. 5, at 818).

The $240,545 consists of $184,801 in advertising costs and $55,745 in sales promotion expense (Exhs. MOC 3-10(c); BSG/JES-5; AG 15-13(a)). The amounts cover a variety of expenditures including print advertising for the Company's EP&S business, a natural gas conversion package, a builder developer gas installation package, and radio advertising for some of its EP&S service offerings (Exh. MOC 1-1). Also included are customer rebates and incentives, on-hold messaging, marketing lists and trade ally expenses such as participating contractor brochures, homebuilders association dues, contractor mediation, and contractor incentives (id.).

In addition to its direct sales and promotional expenses, the Company also included $1,136,100 in indirect sales promotional expenses in its test year cost of service (Exhs. MOC-1-1; MOC-1-3; Tr. 5, at 818; RR-AG-30). Indirect sales promotional expenses include labor, materials and supplies, outside services, rents or leases, employee expenses, company memberships, utilities, and miscellaneous expenses (Tr. 5, at 825-828; RR-AG-30).

This figure includes expenses of $270,890 incurred directly by Bay State and $865,210 billed to the Company by Northern Utilities (RR-AG-30).

The sum of the direct advertising and sales promotion expense of $240,545 and the indirect sales promotion expense of $1,136,100 produces a total advertising and sales promotion expense of $1,376,645. This total expense consists of $184,801 in advertising expense associated with Bay State's EP&S division and $1,191,844 in direct and indirect sales promotion costs (Exh. MOC 3-10(c)).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Department should exclude from the cost of service $1,376,645 in sales promotional expenses, because the Company failed to: (1) remove the sales promotional costs associated with conversions from electricity to gas; (2) conduct a cost/benefit analysis of the promotional programs or prove that the promotional expenses were prudently incurred; and (3) prove that the $1.3 million was a reasonable expense (Attorney General Brief at 76, citing D.T.E. 03-40, at 247-249; Attorney General Reply Brief at 30).

The Attorney General asserts that, in accordance with the provisions of G.L. c. 164, § 33A, the Department does not allow recovery of promotional expenses relating to the conversion of utility services between Department-regulated industries (Attorney General Brief at 77). Despite this statutory and regulatory prohibition, the Attorney General contends that the Company did not track or remove the sales promotion expenses associated with the 844 residential, commercial and industrial conversions from electricity to gas that occured during the test year (id. at 76, citing RR-AG-36; Tr. 6, at 960-964). According to the Attorney

General, the Company's failure to track electric versus heating oil conversions leaves the Department unable to determine which sales promotional expenses are recoverable (Attorney General Brief at 77). The Attorney General contends that the Company has failed to meet its burden of proof and, therefore, the Department should exclude all sales promotional expenses related to these 844 conversions from the cost of service (id.).[128]

The Attorney General also states that in order to recover promotional expenses as part of the Company's base rates, the Company needs to demonstrate net benefits to ratepayers (id., citing D.T.E. 03-40, at 243-244). The Attorney General states that the Company could not specifically or indirectly identify or produce an incremental net benefit analysis for the sales promotional programs that were conducted prior to the implementation of said programs (Attorney General Brief at 78). The Attorney General also states that the Company could not provide any type of internal rate of return ("IRR") analysis for such programs (id.). The Attorney General contends that without such an analysis, the Company has failed to meet the Department's requirements for inclusion of promotional expenses in the test year cost of service (id.).

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[128] On reply brief, the Attorney General specifies that $12,143 in EP&S-related advertising expenses should be excluded from cost of service, along with 25.44 percent of the remaining $172,658 for electric-to-gas conversions (Attorney General Reply Brief at 36-37, citing RR-AG-32).

b. MOC

The MOC states that in order to recover sales promotion expenses, a company must demonstrate that the program results in net benefits to ratepayers (MOC Brief at 11, citing D.T.E. 03-40, at 243; D.T.E. 01-56, at 67; D.T.E. 92-111, at 193). The MOC argues that the Department has also distinguished between promotional programs that are treated above-the-line and below-the-line for ratemaking purposes, and that any cost analysis justifying recovery must include both direct and indirect costs (id. at 12).

Moreover, the MOC notes that the Department has, in the past, excluded promotional expenses from cost of service during times of high gas prices and constrained supplies (id. at 4, citing Lowell Gas Company, D.P.U. 19037/19037-A at 28 (1977)). The MOC contends that, while the Department was not persuaded by MOC's arguments during D.T.E. 03-40 that conditions were sufficient to trigger denial of promotional programs from cost of service, gas prices are now at an unprecedented level and supply concerns are even more serious than those present during D.T.E. 03-40 (MOC Brief at 4). The MOC requests the Department to be mindful of these facts and consider the current state of the energy industry when reviewing those sales promotion expenses designed to attract conversion customers to the Company (id.).

The MOC identifies $1,376,645 in direct and indirect sales promotion expenses incurred by Bay State during the test year, of which $184,801 represents advertising expenditures and $1,191,844 represents direct and indirect sales promotion costs (id.). First, the MOC asserts that the Company has failed to perform the required analyses as mandated by the Department's prior orders for evaluating the propriety of advertising expenses (id. at 3; MOC Reply Brief at 2). Specifically, the MOC asserts that Bay State failed to assemble the

advertisements for cost recovery by the subgroups prescribed by the Department, and has not explained why it did not follow the Department's requirements with regard to grouping and analyzing advertisements and their related costs (MOC Brief at 10; MOC Reply Brief at 3). The MOC asserts that the Company's approach does not facilitate review of its advertising costs, making it difficult to review and ascertain the appropriateness of the Company's advertising expense requests (MOC Brief at 11). The MOC asserts that Bay State's failure to present its advertising in the format required by the Department does not shift the burden of proving the propriety of the Company's request (id. at 10). Additionally, the MOC also asserts that the advertisements themselves are mainly designed to promote the Company's EP&S business to residential customers and do not include any advertisements directed at contractor, trade allies, or promoting conversions (id.). The MOC requests that the Department reject the Company's requested allowance of $184,801 in advertising expenditures (id. at 11; MOC Reply Brief at 3).

Turning to the Company's other sales promotion expenses of $1,191,844, the MOC argues that Bay State failed to provide a net benefits analysis for these expenditures, including an IRR analysis for each promotional program, and also the Company does not explain why an analysis was not conducted (MOC Brief at 12-13; MOC Reply Brief at 4). Additionally, the MOC argues that Bay State failed to identify and include indirect costs in its initially-reported sales promotion expenditures of $240,545, and that it was only upon cross-examination and the answer to a record request that the parties discovered there were also indirect costs of $1,136,100 associated with the Company's sales promotion programs (MOC Brief at 14, citing Exh. MOC-1-3; Tr. 5, at 818; RR-AG-30). The MOC states that Bay State's justification for

including the sales promotion expenses in rates because the Company's EP&S business earned a $5.7 million profit in the test year fails to satisfy the Department's burden of proof, and that the Company has not shown that it would not earn the $5.7 million in net revenues without incurring the $1,191,844 in promotional costs (MOC Brief at 14; MOC Reply Brief at 5). Therefore, the MOC advocates that the Company's test year direct and indirect promotional program expenditures of $1,191,844 should be denied (MOC Brief at 14-15).

c. Company

Bay State argues that it has demonstrated that for above-the-line advertising costs of $184,801, all the costs were attributable to its EP&S program, which it considers beneficial to customers because it adds revenue, lowers the overall revenue requirement, and is in direct competition with non-regulated products and services (Company Brief at 121, citing Exhs. BSG/JES-1, at 72; BSG/SHB-1, at 52). The Company asserts that they have not and will not request recovery of any advertising costs that are below the line (Company Brief at 121, citing Exhs. MOC-1-3; MOC-3-10).

Bay State states that the benefit of sales promotions programs totaling $1,191,844 is shown in the $5.7 million in net revenue yielded by the EP&S business that directly reduces the Company's revenue deficiency and reduces the obligation on customers (Company Brief at 121, citing Exh. BSG/SHB-1, at 58; Company Reply Brief at 22). The Company argues that although it did not conduct a pre-implementation IRR analysis for each promotional program, these programs have been in effect for many years (Company Reply Brief at 23). Bay State asserts that, given its relatively modest promotional program in comparison to the one at issue in D.T.E. 03-40, the cost of a full IRR analysis could easily exceed actual program expenses

(id. at 24). The Company urges the Department to apply a materiality test in determining whether promotional programs should be subject to a complete IRR analysis (id.).

The Company asserts that the appropriate incremental costs and revenues were allocated to these businesses in order to ensure that ratepayers do not subsidize separate business activities, and that ratepayers share in any benefits attributable to these activities (Company Brief at 12, citing Exh. BSG/SHB-1, at 56-57; Company Reply Brief at 23). Bay State maintains the Attorney General's estimate of electric-to-gas conversions is overstated, and that, in any event, it would be inappropriate to exclude the entire balance of sales promotion expense because of a few electric-to-gas conversions of which that the Company may not even be aware (Company Reply Brief at 24-25). The Company concludes that its EP&S advertising, sales and promotions expenses are an appropriate and reasonable cost of doing business that directly benefits ratepayers, and that the Attorney General's and the MOC's challenges should be dismissed (Company Brief at 122).

3. Analysis and Findings

a. Standard of Review

Pursuant to G.L. c. 164, § 33A, gas or electric companies may not recover from ratepayers direct or indirect expenditures relating to promotional advertising. D.P.U. 92-210, at 98; Bay State Gas Company, D.P.U. 92-111-A at 8. Exempt from this provision, however, is advertising, "which informs . . . consumers of and stimulates the use of products or services which are subject to direct competition from products or services of entities not regulated by the [D]epartment or any other governmental agency." G.L. c. 164, § 33A.

In order to facilitate the review of utility advertising, the Department has established four primary groupings: (1) image-related; (2) informational; (3) promotional; and (4) miscellaneous charges.[129] D.P.U. 96-50 (Phase I) at 64; D.P.U. 92-111, at 182-191; D.P.U. 90-121, at 130-136. The Department further separated the promotional class into the following: (1) advertising which promotes the use of gas explicitly in competition with an unregulated fuel; (2) advertising which promotes the use of gas but does not explicitly reference an unregulated fuel; and (3) advertising which promotes nonutility operations. D.P.U. 93-60, at 162. In this context, the term "explicitly" as applied to competition with an unregulated fuel means that the advertisement must leave the reader or listener with the reasonable impression that the target of the advertisement is an unregulated fuel. D.P.U. 90-121, at 133.[130]

To recover promotional expenses through base rates, a company must demonstrate that the program results in net benefits to ratepayers. D.T.E. 01-56, at 67; D.P.U. 92-111, at 193. The measurement of net benefits is dependent upon the particular ratemaking treatment to be accorded to the program. In the case where the utility seeks to include the program above-the-line for ratemaking purposes, an incremental approach is used because ratepayers would receive the benefit of any incremental profitability. D.P.U. 90-121, at 35;

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[129] The Department recognizes the existence of additional advertising categories, such as political advertising, which is explicitly precluded from rate recovery under G.L. c. 164, § 33A, and conservation-related advertising. D.P.U. 92-210, at 99, n.56.

[130] The Department has long-recognized the difficulties associated with determining the eligibility of advertising expense for rate recovery. As we noted in D.T.E. 03-40, at 277, the review process is akin to "commanding haystacks to render up their needles."

D.P.U. 87-122, at 20. If a utility seeks to place the program below-the-line for ratemaking purposes, a portion of common, or indirect, costs must be assigned to the program because ratepayers are supporting the cost of utility resources that are being used in part to support the program. D.P.U. 87-59, at 10. Whatever ratemaking treatment may be proposed for a promotional program, the cost analysis should appropriately include both direct and indirect expenses, so that both the economic benefits of the program and the appropriate ratemaking treatment can be determined. See D.T.E. 01-56-A at 16-17.

b. Cost-Benefit Analysis

Regarding the Attorney General and MOC's concerns pertaining to the Company's lack of cost/benefit analysis for the advertising costs incurred by Bay State, the Department recognizes that, unlike the situation where a company has an extensive advertising or promotional program, Bay State's advertising and promotional expenses are relatively modest, totaling less than $1.2 million during the test year. Cf. D.T.E. 03-40, at 227, n.99 (test year advertising and promotional expense of $13,667,512). Given the Company's relatively modest promotional program in comparison to the one at issue in D.T.E. 03-40, the cost of a full internal rate of return analysis would prove to be rather costly in comparison to the actual program expenses and therefore detract from the benefit to ratepayers. The Department further finds that the Company has shown benefit to customers in the net revenue yielded by the EP&S business, which includes the advertising and promotional expenses, directly reducing the Company's revenue deficiency and the customers' obligations (Exh. BSG/SHB-1, at 58).

c. State of Energy Industry

MOC asserts that the Department should exclude promotional expenses from the cost of service during times of high gas prices and constrained supplies and that the Department had expressed its reservations about the propriety of gas utility promotional programs in the wake of gas curtailments during the 1970s. Haverhill Gas Company, D.P.U. 19660, at 6 (1979); D.P.U. 19037/19037-A at 28. During the time of those decisions, the Department excluded from cost of service promotional program expenses that could not be reasonably shown as conservation-related expenditures. D.P.U. 19037/19037-A at 28.

However, the Department is not persuaded at this time that present conditions involving high gas prices and potential supply constraints are sufficient to trigger reimposition of our previous treatment of promotional programs. The Department allows expenses for promotional measures to be recovered through base rates, if those measures collectively provide net benefits to ratepayers. Commonwealth Gas Company, D.P.U. 87-122, at 19-24 (1987). It is generally true that increased throughput results in increased revenues, which in turn, spread fixed costs among a company's ratepayers whenever rates are reset. We are not inclined to depart from our net benefit precedent in this proceeding. Therefore, while the Department will examine the Company's advertising and promotional programs under long-established ratemaking standards, we decline to adopt the MOC's proposed per se exclusion standard.

d. Promotional and Informational Advertising

In this case the only actual advertisement provided by the Company came in the form of Exhibit BSG/JES-5, which includes copies of advertising materials that the Company has used during the test year to inform customers of the services it provides, totaling $200,871

(Exhs. BSG/JES-1, at 71 of 72; MOC-3-9) [131]. A Department review of this evidence reveals that all of these advertisements are either promotional or informational in nature. The Company's promotional advertisements are identified on lines 1, 2, 3, 7, and 8 from Exhibit BSG/JES-5, and total $83,029 in expense. These advertisements promote the Company's Guardian Care Service Business which provides service for customer-owned equipment (Exh. BSG/SHB-1, at 55). This business operates fully within the gas utility and is marketed under the service mark "Guardian Care" (id.). Revenues and expenses associated with the Guardian Care program are treated above-the-line for ratemaking purposes, with profits being credited to ratepayers (Exh. BSG/SHB-1, at 55; Tr. 3, at 587). The Department finds that these advertisements inform consumers of and stimulate the use of products or services which are subject to direct competition from products or services of entities not regulated by the Department or any other governmental agency. D.P.U. 90-121, at 130. Therefore, because these advertisements do not encourage a consumer to switch from one Department-regulated service to another Department-regulated service, they meet the requirements of G.L. c. 164, § 33A and the Department's requirements regarding promotional advertisements. The costs associated with the advertisements are to be included in the Company's cost of service.

Informational advertisements are those advertisements which directly provide the reader or listener with necessary information concerning the company's operations. Some examples of informational advertising include announcements urging customers to conserve, advertisements for job openings, information on office location and telephone numbers,

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[131] Exhibit BSG/JES-1 contained slight inaccuracies and was corrected in Exhibit MOC-3-9.

holiday office schedule and new company procedures. The cost of these advertisements may be recovered through rates. D.P.U. 92-111, at 183-184; D.P.U. 90-121, at 131; D.P.U. 1270/1414, at 28-31. The Company's informational advertisements are identified on lines 4, 5, and 6 from Exhibit BSG/JES-5, and total $115,193 in expense. These advertisements inform consumers about scheduling annual home heating and cooling inspections which are beneficial in regards to both efficiency and safety. Therefore, these advertisements meet the requirements of G.L. c. 164, § 33A and the Department's requirements regarding promotional advertisements, and the costs associated with the advertisements are to be included in the Company's cost of service.

e. Indirect Promotion/Advertising Expense

The Company has shown that all of the Company's indirect sales promotion and advertising expenses were attributable to its EP&S programs. As noted above, G.L. c. 164, § 33A denies recognition in rates of the costs of political advertising and advertising that promotes the use of the utility service, but exempts the costs of advertising, "which informs . . . consumers of and stimulates the use of products or services which are subject to direct competition from products or services of entities not regulated by the [D]epartment or any other governmental agency." G.L. c. 164, § 33A. In addition, in order to recover promotional expenses through base rates, a company must demonstrate that the program results in net benefits to ratepayers. D.T.E. 01-56, at 67; D.P.U. 92-111, at 193. The measurement of net benefits is dependent upon the particular ratemaking treatment to be accorded to the program. In the case where the utility seeks to include the program above-the-line for

ratemaking purposes, an incremental approach is used because ratepayers would receive the benefit of any incremental profitability. D.P.U. 90-121, at 35; D.P.U. 87-122, at 20.

Bay State is proposing above-the-line treatment of its EP&S programs. As noted above, the Company has shown a benefit to customers in the net revenue yielded by the EP&S business, which includes the advertising and promotional expenses, directly reducing the Company's revenue deficiency and the customers obligations (Exh. BSG/SHB-1, at 58). For this reason, the Department denies the Attorney General's and MOC's proposal to eliminate the cost of this type of advertising from the Company's cost of service.

f. Electric Conversion Customers

The Attorney General disputes the extent to which the Company's promotional programs foster conversions from electricity to gas, which would result in disallowance of the associated costs pursuant to G.L. c. 164, § 33A. The Company maintains that it would be inappropriate to disallow the sales promotion expenses because of a few conversions from electricity to gas of which the Company may not have been informed and does not have a record. However, the record indicates that during the test year 844 customers converted from electric heat to gas heat (RR-AG-36). Pursuant to G.L. c. 164, § 33A, the Department must remove both direct and indirect expenditures associated with the conversion of customers from one Department-regulated industry to another. During the test year, the number of electric to gas conversions represented 25.44 percent[132] of the total conversions undertaken by the Company (id.; Exh. AG-6-14).

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[132] This value is calculated as follows: 844 electric to gas conversions / 3,317 total conversions = 25.44 percent (RR-AG-36, Exh. AG-6-14).

Therefore, the Department will reduce the level of promotional expense calculated above by 25.44 percent in order to remove a representative level of expenses related to the conversion of eligible customers from electric to gas heat as a result of the Company's promotional programs. This results in an allowable promotional expense level of $1,026,369 (Exhs. MOC 3-10(c); MOC 1-3; MOC 1-1).[133] Accordingly, the Department will reduce the Company's cost of service by $350,285.

g. Conclusion

Based on the above analysis, the Department has excluded $350,285 in advertising expense from cost of service in addition to Bay State's proposed adjustment. Accordingly, the Department will reduce the Company's proposed cost of service by $350,285.

P. Westborough Lease Expense

1. Introduction

Bay State maintains its corporate headquarters in Westborough (Tr. 12, at 1935-1936). The Company originally purchased the 89,145 square foot building in the early 1990s, but in June of 1997 executed a 15-year sale/leaseback agreement with Trinet Corporate Realty Trust and now is a tenant in the building (Exhs. AG 3-41 (Supp.); AG 3-42).[134] Under the terms of the lease, the Company leases the building for a fixed monthly rent that escalates annually, plus various other rental components and management fees (Exhs. AG 1-65; AG 3-42(2a)

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133 This value is calculated as follows: (1-0.2544)*(184,810+1,191,844) = 1,026,369 (Exhs. MOC-3-10(c), MOC-1-3, MOC-1-1).

134 The building is now owned by Oasis Friberg Parkway Westborough LLC (Exh. AG 3-42(2b) at 3).

at 7-9). The lease also requires Bay State to pay associated taxes and operating expenses for the facility (Exh. AG 3-42, at 8-9). The Westborough office is used by both Company and NCSC personnel, the latter of whom are mostly assigned on a part-time basis (Exh. UWUA 3-12; Tr. 12, at 1944; RR-AG-2). Because both Company and Northern Utilities personnel use the Westborough office, 16.4 percent of the total lease and operating expense was charged back to Northern Utilities, based on the results of a 2004 building space usage study (Exh. AG 1-27(D), at 6).

During the test year, the Company booked $1,172,165 in lease expense and $486,921 in operating expenses associated with the building, including $71,788 in property taxes (Exhs. AG 1-29; UWUA 3-32). In addition, the Company subleases 16,216 square feet of the building to two other tenants, receiving $179,654 in sublease payments during the test year (Exhs. AG 1-27(G); AG 3-41; Tr. 12, at 1938-1939; RR-UWUA-6).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that Bay State failed to provide the basic lease information, cost/benefit analysis, market valuation or appraisals that were required prior to the sale of the property (Attorney General Reply Brief at 28). This lack of information, according to the Attorney General, precludes the Company from validly contending that the overall lease expense is reasonable, based on market prices, or less expensive than retaining ownership (id.).

The Attorney General contends that the Westborough office is now far in excess of Company needs, with only 26 Bay State employees currently located in a facility that had 138

employees as recently as 2000 (id.). The Attorney General maintains that the various subleases at the building fail to completely mitigate the financial burden of the lease payments, and claims that Bay State ratepayers were denied any benefit of the subleasing income, because those revenues were entirely allocated to Northern Utilities (id. at 29, citing Exh. AG 3-28, Att. at 5).

The Attorney General contends that the Department requires that lease expenses be prorated to eliminate expenses not associated with utility service (Attorney General Reply Brief at 29, citing D.T.E. 03-40, at 173). Based on an inflation-adjusted per-capita employee expense calculated by Local 273 of $11,661, applied to 22 Bay State employees housed at Westborough during the test year, the Attorney General proposes that the Department allow a revised lease expense of $256,542, and, therefore, reduce the Company's proposed cost of service by $736,009 (Attorney General Reply Brief at 29-30). In addition, the Attorney General proposes that the Department remove 18.2 percent of the gross lease expense from the cost of service to recognize subtenant use of space (id. at 29).

b. Local 273

Local 273 maintains that, despite Bay State's representations during the evidentiary hearings in D.T.E. 98-31 that it would maintain its Westborough office, the Company's headquarters are now "a virtual ghost town" compared to its pre-merger status (UWUA Brief at 60). Local 273 argues that while the Westborough office may have been a reasonable size for Bay State's workforce when it housed 198 staff in 1998, the facilities are clearly excessive for the 22 Company employees and approximately 20 NCSC employees located there during the test year (UWUA Reply Brief at 10). Local 273 calculates that the Company's

per-employee office costs associated with Westborough were $24,990 during the test year, representing an increase of 2.8 times since 2000 (UWUA Brief at 61; UWUA Reply Brief at 10).

Because Bay State now uses only a portion of the Westborough office, Local 273 proposes an adjustment to the Company's lease and operating expenses associated with that office (UWUA Brief at 61). Reasoning that the Company's total office expenses at Westborough increased by what it considers to be a reasonable 10.95 percent between 2000 and 2004, Local 273 proposes that the Company be allowed to recover only an inflation-adjusted per-employee cost of $11,661, multiplied by 55 Bay State and NCSC employees currently located at Westborough (id. at 62). Local 273 considers this to be a conservative approach, given its assessment of evidence that Westborough actually housed only 44 to 48 employees in 2004, and that the Company had already been paying for excess space by 2000 (id.; UWUA Reply Brief at 10, n.15).

c. Company

Bay State argues that its lease expense is a contracted amount set at the time that the lease agreement was executed in 1997, and is commensurate with both the property itself and then-prevailing market conditions (Company Brief at 119; Company Reply Brief at 21-22). The Company contends that it has sought to mitigate the lease expense through subleasing (Company Reply Brief at 21). Bay State argues that the Attorney General's and Local 273's proposed adjustments have no rational basis and fail to recognize the Company's obligations under the lease (Company Brief at 119; Company Reply Brief at 21). The Company also maintains that the interveners fail to recognize that Bay State shares the Westborough lease

expense with Northern Utilities, which bears approximately 16.5 percent of the gross expense net of sublet revenues (Company Reply Brief at 20).

3. Analysis and Findings

A company's lease expense represents an allowable cost qualified for inclusion in its overall cost of service. D.T.E. 03-40, at 171; Nantucket Electric Company, D.P.U. 88-161/168, at 123-125 (1988). Increases in rental expense based on executed lease agreements with unaffiliated landlords are recognized in cost of service, as are operating costs (maintenance, property taxes, etc.) that the lessee agrees to cover as part of the agreement. D.P.U. 95-118, at 42 n.24; D.P.U. 88-67 (Phase I) at 95-97. The Department has also found that the standard for inclusion of lease expense is one of reasonableness. D.P.U. 89-114/90-331/91-80 (Phase One) at 96.

Bay State entered into a written lease agreement for its Westborough offices (Exh. AG 3-42(2a)). Thus, the Department finds that the lease is eligible for inclusion in the Company's overall cost of service. However, contrary to the Company's argument on brief, the Department's inquiry can not end there. The fact that a lease agreement may have been appropriate in the past does not necessarily justify continuation of the arrangement into the indefinite future. The issue is not, as Bay State appears to argue, whether disallowance of all or a portion of the Company's lease expense will give rise to a claim of interference with contractual relationships, but rather who will bear these costs. Therefore, the Department must also examine the overall reasonableness of the lease. D.T.E. 03-40, at 171.

In D.P.U. 86-33-G at 291, the Department addressed a similar issue involving central office space:

> We recognize that buildings are not designed so that every square inch of space will be filled with furniture, equipment, and stored items; therefore, there will always be a certain amount of normal vacant floor space in any building. Thus, vacant floor space, in a building that is otherwise used and useful, can be considered excess capacity only if its amount exceeds what is reasonable.

The Department has also found that, if a company makes reasonable efforts to reuse the space where possible, it would be inappropriate to reduce the company's cost of service for the excess space. Id. at 291-292.

In the case of the Westborough office, Bay State is leasing a 89,145 square foot building, with rentable area of 72,929 square feet, that once housed approximately 385 employees but now houses approximately 55 Company and NiSource personnel (Exh. UWUA 1-1; Tr. 12, at 1935). The Company concedes that the amount of space in the building is in excess of its needs, and had relied on subleasing as a reasonable alternative (Tr. 12, at 1938). While the Company has had a measure of success in subletting extra space, the fact remains that the square footage per employee has risen from 231 square feet to 1,620 square feet (Exhs. AG 1-27(G) at 6; UWUA 1-1). Allowing for 16,196 square feet of nonrentable areas and 16,216 square feet under sublease, Bay State is presently paying for 56,713 rentable square feet, equal to 1,031 square feet per employee, with a portion of this expense being recovered through the management fee paid by Northern Utilities (Exh. AG 1-27(G) at 6). The Department finds this level of space to be in excess of the Company's requirements to serve ratepayers needs. At the same time, the Department recognizes the benefits to having the Company's corporate headquarters in a central location relative to its three operating divisions (Tr. 12, at 1935-1938). See D.T.E. 03-40, at 172.

The Department will adjust the Company's Westborough lease and operating expenses. First, because the Company subleases 16,216 square feet of its 89,145 square feet, the Department finds that an adjustment to cost of service is appropriate to prevent double-recovery of this pro rata share of lease and operating costs from ratepayers. D.T.E. 03-40, at 173; D.P.U. 95-118, at 139; D.P.U. 92-210, at 11-12. Therefore, the Department will reduce the Westborough lease and operating expenses by 18.18 percent, representing the portion of the building under sublease, producing a reduction to lease expense of $213,155 and a reduction to operating expense of $88,522. Similarly, because the Company allocates 16.4 percent of the building's costs to Northern Utilities, the Department will reduce lease expense by an additional $192,235 and reduce operating expense by an additional $79,855, respectively (Exh. AG 1-27(G), at 6). This results in a reduction to lease expense of $405,390 and a reduction to operating expense of $168,377, associated with subleasing and allocations to affiliates.

Next, the Department will apply a pro rata reduction to the Company's remaining lease expense of $766,775 and operating costs of $318,544 based on square footage per employee, and apply the results to the remaining 58,220 square feet. Based on the 190 full- and part-time employees located at Westborough in 1998, the year prior to the Company's acquisition by NiSource, and 89,145 total square feet, there was 469 square feet per employee in 1998 (Exh. UWUA 1-1). This factor, multiplied by the 55 Company and NiSource personnel located at Westborough during the test year, produces 25,795 square feet of space to be included in cost of service, representing 44.3 percent of the total square footage. Therefore, the Department will reduce the remaining portion of the Westborough lease and operating

expenses by 55.7 percent, resulting in a reduction to lease expense of $427,094 and a reduction to operating costs of $177,429.

The sum of these adjustments represent a total reduction to lease expense of $832,484 and a total reduction to operating expense of $345,806. Bay State has already recognized $179,654 in subleasing revenues in its cost of service (RR-UWUA-6). Additionally, the Company allocates 16.4 percent of total lease and operating expense of $1,659,086, along with 16.4 percent of subleasing revenues, to Northern Utilities for a net allocation of $242,627 (Exh. AG 1-27(D) at 6).[135] Accordingly, the Department will reduce the Company's test year cost of service by $756,009.

Q. Amortization of FAS 109 Expense

1. Introduction

Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes" ("FAS 109"), which took effect December 31, 1992, requires companies to recognize on their financial statements all previously unrecorded future income tax liabilities (Exh. BSG/JES-1, at 45). As a result of complying with that mandate, the Company recorded a future tax liability of $4,385,240, with an offsetting debit to Account 186, Miscellaneous Deferred Debits (id. at 45-46; Exh. AG 1-2(3) (2004 Annual Return to the Department) at 27). In D.P.U. 92-111, at 172-173, the Department approved recovery of the Company's FAS 109 regulatory asset over approximately 25 years, representing the remaining estimated life of the

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[135] Equal to $1,659,086 x 16.4 percent, less the product of $179,654 x 16.4 percent.

Company's utility plant, at the rate of $174,017 per year.[136] As of the end of the test year, $2,286,034 of the original deficiency from D.P.U. 92-111 remained to be recovered (Exh. BSG/JES-1, at 46).

Since the Department's decision in D.P.U. 92-111, the Company's future income tax liabilities have increased by an additional $1,167,619 (id.). Of this amount, $1,088,522 is attributable to the 1993 increase in the Federal income tax rate from 34 percent to 35 percent, and $79,097 is associated with 1992 timingdifferences which were not factored into the calculation of the original tax deficiency (id.; Exh. BSG/JES-1, Workpaper JES-11). The Company proposes to amortize this additional deficiency, for accounting and ratemaking purposes, over the remaining amortization period of 13.0334 years, thus increasing the annual amortization by $89,587 per year, to $263,604 (Exhs. BSG/JES-1, at 46; BSG/JES-1, Workpaper JES-11).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that Bay State should have followed generally accepted accounting principles ("GAAP") and begun amortizing the additional deferred income tax deficiency at the time the liability was known, instead of deferring recognition until a base rate case, as the Company did (Attorney General Brief at 81, citing Exh. AG-9, at 20-21). The

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[136] The 25-year life was equal to the remaining life of the Company's utility plant, based on an approved composite depreciation accrual rate of 3.97 percent. D.P.U. 92-111, at 126, 173. This approach is referred to as the "South Georgia" method, because it was first prescribed by the Federal Power Commission in South Georgia Natural Gas Company, FPC RP-77-32 (May 5, 1978).

Attorney General notes that if the Company had begun the amortization of the additional deficiency during 1993, the annual amortization requested in this proceeding would have been reduced by $43,000 (Attorney General Brief at 81, citing Exh. AG-9, at 21, Sch. DJE-4). Accordingly, the Attorney General concludes that the Department should reduce the Company's proposed adjustment to its deficiency in accumulated deferred income taxes, and the cost of service, by $43,000 (Attorney General Brief at 81-82).

b. Company

Bay State maintains that its has accounted for its FAS 109 obligations consistent with GAAP (Company Brief at 127). The Company points out that the deferred income tax shortfall associated with 1992 timing differences was not known and measurable at the time of its last rate case in D.P.U. 92-111, because that filing was based upon a 1991 test year and the Company did not file its tax return until September of 1992 (id., at 127-128). Therefore, the Company concludes that it could not have included those deferred income taxes in that case, or begun amortizing them at that time (id.). Furthermore, Bay State contends that it was unable to revise its FAS 109 amortization prior to this case, because the South Georgia method used to determine the FAS 109 amortization requires any adjustments to be made by the appropriate regulatory commission (id., citing Tr. 23, at 3881-3882; 78 FERC ¶ 62,135, 1997 FERC LEXIS 2837 (January 31, 1997)).

3. Analysis and Findings

Bay State has apparently misconstrued the Attorney General's position. The Attorney General is not arguing that the additional deferred income taxes should have been recorded earlier for accounting or ratemaking purposes. Rather, the Attorney General contends that the

Company should have commenced amortizing the additional deferred taxes for accounting purposes over the 25-year period approved in D.P.U. 92-111, once the additional obligations became known (Attorney General Brief at 81; Exh. DTE-4; Tr. 18, at 2918-2919). Nonetheless, we disagree with the Attorney General.

As an initial matter, none of the parties in this case dispute either Bay State's obligation to record a regulatory asset for the additional tax deficiency, or the Company's reasonable expectation that the asset would be ultimately recovered through rates (Tr. 18, at 2921-2922). The issue here is when the amortization of that regulatory asset should have begun. Had the Company begun amortizing the regulatory asset when the deficiency became known, as the Attorney General proposes, the Company would be required to write off an accumulated FAS 109 liability of approximately $516,000.[137] By delaying the amortization of the income tax deficiency until its next base rate case, the Company's earnings will not suffer because the expense of amortizing the tax deficiency will be offset by the revenues received from customers to recover that expense (Tr. 18, at 2922). This process is referred to as the "matching concept" and is in accordance with GAAP (id.). Moreover, the Department is persuaded that the Company is precluded by FERC from adjusting its South Georgia amortization until such a time as it receives our approval, most appropriately as part of a rate filing brought under G.L. c. 164, § 94 (Tr. 23, at 3881-3882; 78 FERC ¶ 62,135). Accordingly, we will permit the Company to recover the additional deferred income tax

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[137] Equal to $43,000 multiplied by the twelve years that elapsed from 1993 through the test year, inclusive.

deficiency over the remaining amortization period of 13.0334 years. The Company's proposed adjustment is approved.

R. NiSource Corporate Jet

1. Introduction

NCSC owns a Raytheon Hawker 800 XP jet that is used to transport employees of NiSource's subsidiaries, including those of Bay State, to meetings throughout NiSource's service territory (Exh. AG 1-54; RR-AG-46). During the test year, NCSC allocated Bay State $150,445 in expenses related to the corporate jet, on the basis of NCSC's overall contract billings over the previous twelve months (Exh. AG 19-27; RR-AG-46).

2. Positions of the Parties

a. Attorney General

The Attorney General maintains that the Company has failed to demonstrate that the jet provides any benefits to ratepayers (Attorney General Brief at 82). The Attorney General argues that while the jet may offer certain travel convenience, this convenience may be outweighed by the cost of alternative means of transportation, such as commercial flights (id.). In fact, the Attorney General claims that only two trips were made to and from Bay State's service territory during the test year, representing a per-trip allocation of $75,222 (Attorney General Reply Brief at 31, citing RR-AG-45). The Attorney General argues that, in the absence of evidence of appropriate cost-containment efforts by the Company, it is not possible to determine whether the aircraft-related costs are prudent or reasonable (Attorney General Brief at 82; Attorney General Reply Brief at 31). Therefore, the Attorney General proposes that the Company's cost of service be reduced by $150,445 (Attorney General Brief at 82).

b. Company

Bay State contends that the NCSC corporate jet is an effective and efficient way to transport employees across NiSource's eleven-state system, while allowing them to conduct business en route to their destinations (Company Brief at 122; Company Reply Brief at 30). The Company points out that because there are no airport hubs at many of NiSource's operating companies, it would be necessary for employees to make multiple connections at a greater cost and delay if they were required to take commercial flights (Company Brief at 122-123; Company Reply Brief at 30).

3. Analysis and Findings

The Department has excluded from cost of service vehicles and vehicle-related expenses when use of those vehicles were found to be unreasonable. Fall River Gas Company, D.P.U. 750, at 15 (1982); Lowell Gas Company, D.P.U. 18571.18572, at 12-13 (1976). In the instant case, NCSC owns an aircraft that is used by Company personnel for Company-related travel.

There is sufficient evidence to conclude that the use of the jet offers a cost-effective means of traveling among NiSource's 16 operating companies, including ten gas and electric distribution subsidiaries spread across nine states (Exh. AG 1-2(3), 2004 Form 10-K at 6). See D.P.U. 94-50, at 359. The evidence does not support the Attorney General's claim that Bay State's ratepayers paid the equivalent of $75,222 per each round trip. Contrary to the Attorney General's claim that the jet was only used twice during the test year for flights to Bay State's service territory, the jet was actually used for twelve direct flights and approximately 190 other round trip flights between Merrillville, Indiana and Columbus, Ohio, mostly by NCSC

employees engaged in general corporate business (RR-AG-46).[138] The Department recognizes that out-of-state travel for business meetings that directly or indirectly affect Bay State's operations may fairly be considered to have been made for the benefit of the Company's ratepayers, and reasonable expenses would be considered allowable for ratemaking purposes. D.P.U. 92-111, at 154. Therefore, it would be reasonable to allocate some portion of these related expenses to Bay State.

The Department has examined both the aircraft-related billings and the allocation formulas used to allocate aircraft costs to Bay State. Although other ways could be devised to allocate aircraft costs among NiSource's affiliates, the existence of other possible allocation outcomes does not render the Company's allocation method invalid. D.T.E. 03-40, at 204; D.P.U. 88-135/151, at 83. Based on our review, the Department finds that the method used to allocate NiSource's corporate jet expenses to Bay State benefits the Company, is provided at cost, and produces both cost-effective and nondiscriminatory results for the use of the aircraft by the Company.

The Department has, however, identified $680 in meals and entertainment expense and $48 in dues and memberships included in the $150,442 test year allocation to Bay State (Exh. AG 19-27). There may be some validity to such costs, but their validity has not been demonstrated. The Department finds that these expenses are not includable in cost of service.

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[138] Record Request AG-45 sought further details on various meals, lodging, transportation and auto travel expenses provided in Exhibit DTE 11-38 that were incurred by Bay State's employees in the course of their duties. These types of travel expenditures are distinct from the operation and maintenance expense associated with NiSource's corporate jet (Exhs. DTE 11-38; AG 19-27; RR-AG-45).

D.T.E. 03-40, at 140-141; D.P.U. 92-111, at 127. Therefore, the Department will reduce the Company's proposed cost of service by $728.

S. Penalties and Late Fees

1. Introduction

During the test year, Bay State incurred $6,500 in Dig-Safe fines from the Department (Exh. AG-4). According to the Company, however, these fines are booked below the line and are therefore not considered for ratemaking purposes (Exh. AG 1-83 (Supp.); Tr. 5, at 815). The Company also booked $215,300 in judgments and settlements arising from litigation filed in the course of the Company's day-to-day operations that are subject to its insurance carrier deductibles (Tr. 3, at 552-553; RR-AG-25).

Further, Bay State paid $3,325 in "customer service guarantees" during the test year (Exh. DTE-1, § 3, at 9). These represent payments made to individual customers as compensation for failure by Bay State to keep service appointments, as required under the Department's service quality plan. See Service Quality Standards, D.T.E. 99-84 (2001). According to the Company, however, these customer service guarantees are booked below the line and are not included in its revenue requirement (Exh. AG 3-4, at 1).

The Company also paid on a voluntary basis $14,107 during the test year to reimburse customers for repairs to their telephone lines (Exh. AG 21-3 (Rev.); Tr. 1, at 141). The telephone lines had been damaged during the installation and removal of the Company's Metscan meter reading devices (Tr. 1, at 141-143). While customer reimbursements incurred prior to March of 2002 were expensed, reimbursements made since March of 2002 have been capitalized as part of the Company's Itron meter installation project (RR-AG-12; RR-AG-80).

Finally, during the test year, the Company incurred various late payment fees and interest charges from various vendors (Exhs. AG-10; AG 3-17; Tr. 21, at 3505-3506). These included late payments for Metscan lease billings and office blueprints (Exhs. AG-10; AG 3-17).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company has failed to substantiate its claim that Dig-Safe fines have been excluded from service, and that the Company does not maintain separate records for penalties incurred by various NiSource subsidiaries (Attorney General Brief at 83). Therefore, the Attorney General proposes that the Department remove all test year Dig-Safe fines from cost of service, and require Bay State to establish separate Dig-Safe accounts so that these fines may be directly assigned to the subsidiary that actually incurred the penalty (id.).

Similarly, the Attorney General contends that $250,310 in payments associated with judgments and settlements have not been demonstrated as benefitting ratepayers (id.). Thus, the Attorney General argues that these payments should be excluded from Bay State's cost of service (id.).

The Attorney General contends that the Company has failed to demonstrate that its customer guarantee payments and reimbursements to customers for telephone line repairs have been excluded from cost of service (id. at 84). Therefore, the Attorney General advocates that the Department reduce Bay State's cost of service accordingly (id.).

Finally, the Attorney General proposes to remove from cost of service various late fees associated with lease expenses and other vendor payments (id. at 83-84, citing Exhs. AG 1-64; AG 3-17). The Attorney General notes that the Company acknowledged that these payments should be excluded from cost of service (Attorney General Brief at 83, citing Tr. 21, at 3505-3506).

b. Company

While Bay State concedes that late fees to vendors should be excluded from cost of service, the Company contests the Attorney General's other related adjustments (Company Brief at 123). First, the Company contends that it has appropriately booked its Dig-Safe penalties below the line to Account 426.50 (id.).

Second, the Company defends its payments from its self-insurance programs as a normal and prudent cost of doing business, contending that its ability to control insurance costs through self-insurance is an important hedge against rising insurance costs (id.). The Company argues that the amount of self-insurance in rates represents only one-fifth of actual claims paid based on a five-year average of payments, thus representing a lower expense level than that of conventional insurance premiums (id. at 123-124).

Third, Bay State argues that it has properly excluded customer guarantee payments from cost of service through its revenue annualization adjustments (id. at 124). Fourth, concerning customer telephone line reimbursements, the Company maintains that it is illogical to consider this expense as a fine or penalty (id. at 124, n.49). Rather, Bay State maintains that this expense clearly falls within the ebb and flow of operating expenses (id.).

3. Analysis and Findings

The Department excludes fines and penalties from cost of service as a matter of public policy. D.T.E. 96-50 (Phase I) at 110; Kings Grant Water Company, D.P.U. 87-228, at 18-19 (1988); Nantucket Electric Company, D.P.U. 1530, at 26 (1983). Similarly, payments associated with customer service guarantees are excluded from cost of service. D.T.E. 03-40, at 261-262.

Concerning Dig-Safe fines, the Company books these to Account 426.50, a subaccount of Account 426, Other Income Deductions (Exh. AG 1-34, at 1; Tr. 3, at 550-552). The Department has examined Bay State's revenue deficiency calculations as well as the information contained in the Company's 2004 annual return, and concludes that Bay State's proposed cost of service does not include Account 426-related expenses. Therefore, the Department is satisfied that the Company has properly excluded Dig-Safe fines from its cost of service. Moreover, the Department is satisfied that NiSource's accounting system does not allocate penalties among various NiSource affiliates, including Bay State (Tr. 3, at 557-558). Accordingly, the Department declines to make any further adjustments for Dig-Safe fines.

Concerning the Company's payment of judgments and settlements, the Department has recognized the role of self-insurance programs in controlling insurance costs. D.P.U. 92-111, at 110. Claims paid through self-insurance are, to the extent a company's underlying actions are found to be prudent, recoverable expenses. D.P.U. 95-40, at 32-33; D.P.U. 87-59, at 35-40. There is no basis or logic supporting the analogy of self-insurance claims paid to

fines and penalties. Accordingly, the Department declines to adopt the Attorney General's proposed per se exclusion of judgments and settlement claims.[139]

Concerning customer guarantee payments, during the test year, the Company booked $34,207 to Account 426.07, Missed Appointments (Exh. AG 1-34, at 1).[140] This reported balance in Account 426.07 leads us to conclude that customer guarantee payments are booked to a subaccount within Account 426, Other Income Deductions (id.). As noted above, the Department has determined that Bay State's proposed cost of service does not include Account 426-related expenses. Therefore, the Department is satisfied that the Company has properly excluded customer guarantee payments from its cost of service. Accordingly, the Department declines to make any further adjustments for customer guarantee payments.

With respect to the Company's reimbursements for damage to customer telephone lines, the Uniform System of Accounts for Gas Companies ("USOA-Gas") specifies that expenditures resulting from damage to the property of others that arises from construction are capitalizable. 220 C.M.R. § 50.00 et seq., Gas Plant Instructions (Components of Construction Costs). Based on our reading of the USOA-Gas and the Company's description of the underlying circumstances behind, we conclude that these reimbursements to customers are expenditures resulting from damage to customer property incurred while installing utility plant, and are thus capitalizable.

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139 The Department has addressed the propriety of the Company's self-insurance program in Section V.F.3, above, of this Order.

140 The Department considers Account 426.07 to include other expenses associated with missed appointments besides the $3,325 in customer guarantee payments reported in Exhibit DTE-1.

Turning to the ratemaking treatment of these reimbursements, Bay State entered into a policy of accepting responsibility for each damage claim (Tr. 1, at 141). Between March of 2002 and May 31, 2005, the Company reimbursed 428 customers for damage to their telephone lines, representing 0.16 percent of the approximately 265,000 accounts which had the Metscan reading devices (id.; Exh. AG 21-3 (Rev.)).[141] There is no evidence to suggest that this de minimis level of claims as a percentage of installations is indicative of Company imprudence or negligence in the physical installation and removal of Metscan meter reading devices. Therefore, the Department declines to accept the Attorney General's proposed adjustment.

T. Legal Retainer From Schiff, Hardin & Waitt

1. Introduction

During the test year, NCSC paid $720,000 to an Illinois law firm, Schiff, Hardin & Waite ("Schiff Hardin") for the services of Peter Fazio, of which $62,238 was allocated to Bay State (Exh. AG 1-93, at 1-5; Tr. 9, at 1591). Mr. Fazio is a partner of Schiff Hardin and also serves as NCSC's Executive Vice President and General Counsel (Exh. AG 1-98 (A) at 1; Tr. 9, at 1591).

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[141] The Company reported that few telephone line damage claims would have been received prior to March of 2002 (RR-AG-80).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the simultaneous positions held by Mr. Fazio raises a conflict of interest concern, because Mr. Fazio is both a partner in a firm providing legal counsel to Bay State, and also an employee of NCSC (Attorney General Brief at 67). The Attorney General maintains that Department precedent requires outside legal fees to be known and measurable, reasonable and cost effective (id., citing D.T.E. 03-40 at 153, 157). The Attorney General also points out that Department precedent requires companies to procure outside legal services based on a competitive bidding process unless the Company shows that its choice of outside counsel is both reasonable and effective (id., citing D.T.E. 03-40 at 148, 153). The Attorney General argues that the fees submitted by the Company are not "known and measurable" since no detail (such as hours billed, billing rate, specific nature of services provided) is provided on the invoices submitted by the Company (id.; Attorney General Reply Brief at 35). The Attorney General further contends that the Company's failure to obtain competitive bids for these outside legal services does not permit a determination as to whether the fees are reasonable and prudent and free of bias, and that NiSource's relationship with Mr. Fazio is insufficient to warrant inclusion of these unverified expenses (Attorney General Brief at 68; Attorney General Reply Brief at 35). Therefore, the Attorney General argues that the Department should remove the $62,238 from the Company's cost of service (Attorney General Brief at 68; Attorney General Reply Brief at 35).

b. Company

Bay State claims that the Attorney General's argument regarding the annual retainer payable to NCSC by the Company is inappropriate (Company Brief at 120). Bay State argues that it has no general counsel of its own, and therefore must rely on the experience and knowledge of NiSource's general counsel (Company Reply Brief at 28). The Company contends that the Company's long-term relationship and the institutional knowledge possessed by Mr. Fazio substitutes for the absence of competitive bidding for Mr. Fazio's services (Company Brief at 120, citing D.T.E. 02-24/25 at 193; Company Reply Brief at 28-29). The Company concludes that the expense is a fixed fee, and thus the associated invoices would not contain the number of hours billed or work performed (Company Reply Brief at 29). Bay State considers the legal retainer is reasonable and justified by the ability of Bay State to have access to the skill and expertise offered by Schiff Hardin and Mr. Fazio (Company Brief at 120).

3. Analysis and Findings

Before the Department is the decision to include or exclude the $62,238 allocation to Bay State that stems from the annual retainer of $750,000 paid by NCSC to Schiff Hardin. Although the legal services being provided by Mr. Fazio were not secured under a competitive bidding process, the Department recognizes that an outside legal firm's long-term relationship and institutional experience with a company can be a proxy for competitive bidding. D.T.E. 03-40, at 148-149; D.T.E. 02-24/25 at 192; D.T.E. 01-56, at 71. Therefore, the Department finds that the prior institutional relationship and expertise provided by Schiff Hardin and Mr. Fazio obviates the need for a competitive bidding process in this instance.

Turning to the Attorney General's argument that the Schiff Hardin allocation is not known and measurable, the invoices themselves, as well as the allocation of those charges to the Company, are indisputably known and measurable. Further the Company is in the best position to judge what its legal needs are and how they are to be met. Therefore, the Department will include the $62,238 allocation to Bay State that stems from the annual retainer paid by NCSC to Shiff Hardin in the Company's cost-of-service.

U. Depreciation Expense

1. Introduction

During the test year, Bay State booked $24,126,454 in depreciation expense (Exh. BSG/JES-1, Sch. JES-7, at 2 (Rev. 1)). The Company proposes to increase its depreciation expense by $4,684,399 to recognize three adjustments: (1) an increase of $4,714,746 to recognize the application of new accrual rates to year-end plant in service; (2) a decrease of $53,211 to remove depreciation expense being allocated to Northern Utilities; and (3) an increase of $22,864 in depreciation expense associated with completed construction in service not recorded to plant accounts as of the end of the test year (Exh. BSG/JES-1, Sch. JES-7, at 1-2 (Rev.)).

The Company developed, for each of its plant accounts, account actuarial service life data by grouping like-aged investments within each property category and identifying the level of retirements through each successive age (Exh. BSG/EMR-1, at 7). The resulting survivor curves were then fitted to standard "Iowa" curves[142] to produce an average service life

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[142] Iowa curves are frequency distribution curves initially developed in the 1930s at Iowa (continued…)

("ASL") (id.). Combining the ASLs with the appropriate Iowa curve, the Company developed a "life-cycle combination curve" ("ASL/Curve") (Exhs. BSG/EMR-1, at 23-27; BSG/EMR-2, § 6). Using the ASL/Curves and net salvage factors, the Company calculated revised account-specific depreciation rates (Exhs. BSG/EMR-1, at 25; BSG/EMR-2, § 2, Table 1). Application of these rates to plant in service as of December 31, 2003 resulted in a composite accrual rate of 4.24 percent, representing an increase from the Company's current composite accrual rate of 3.42 percent that was based on a depreciation study prepared in 1998 (Exhs. BSG/EMR-1, at 5; BSG/EMR-2, § 2, Table 1).

2. Positions of the Parties

a. Attorney General

i. Overview

The Attorney General argues that Company's proposed depreciation rates are incorrect because its underlying net salvage and life curves are incorrect (Attorney General Brief at 55-56).[143] He contends that the Company's depreciation study lacks specific data required to evaluate the proposed values, service lives, and salvage parameters, relying instead on assertions and unidentified sources (id. at 64-65; Attorney General Reply Brief at 21-22). The

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[142] (…continued)
State University, and are widely accepted in determining average life frequencies for utility plant (Exh. BSG/EMR-1, at 26).

[143] The Attorney General points out that Bay State is requesting $463,586,036 of negative net salvage for all its investment over the entire life of its plant, representing a $104,525,053 increase in the level of negative net salvage (Attorney General Brief at 56, citing Exhs. AG-6, Sch. JP-1; BSG/EMR-2, Table 1a, at 2-3). Of this amount, the Attorney General calculates that $80,060,569 is attributable to the Company's mains and services accounts (id.).

Attorney General identifies a number of accounts and subaccounts for which he proposes the use of differing ASLs, Iowa curves, and salvage factors (Attorney General Brief at 57-66; Attorney General Reply Brief at 22-27). These are discussed below.

ii. Salvage Factors

(a). Account 367 - Mains[144]

The Attorney General opposes Bay State's proposed net salvage factor of negative 15 percent for Account 367 - Mains and its subaccounts, and proposes instead a salvage factor of negative ten percent (Attorney General Brief at 56). In support of his proposed salvage factor, the Attorney General argues that Bay State has failed to demonstrate a nexus between the various data points contained in its analysis and its actual analysis of the data, but rather relies on generalized phrases, such as "anticipated" or "experience and expectations associated with potential local regulations and resulting manpower requirements" to somehow arrive at its proposed salvage factor (id. at 57; Attorney General Reply Brief at 22-23).

The Attorney General states that the Company's cost of removal assumptions for Account 367 rely on an assumed 2.75 percent annual inflation rate that must be disregarded for several reasons (Attorney General Brief at 57). First, the Attorney General maintains that historic data do support the Company's premise that inflation is the sole factor to be considered for future changes in cost of removal (id. at 58, citing Exh. AG-6, at 15; Attorney General

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144 The Company's depreciation study relies on account numbers from both the Department's Uniform System of Accounts for Gas Companies and the accounting system prescribed by the Federal Energy Regulatory Commission (Exh. BSG/EMR-2; Tr. 11, at 1873-1875). For consistency, the Department will reference all accounts using the Uniform System of Accounts for Gas Companies.

Reply Brief at 24). For example, the Attorney General alleges that Bay State was unable to provide any analysis demonstrating that future retirements through the Company's SIR program would produce salvage factors greater than a negative ten percent (Attorney General Reply Brief at 23-24). Second, the Attorney General argues that Bay State's witness disregarded his own analysis indicating a forecasted cost of removal of negative 23 percent (Attorney General Brief at 58). Third, the Attorney General questions the Company's regression analysis because Bay State's witness could not explain the purpose of the R squared statistic, which underlies the linear regression analysis (id., citing Exhs. BSG/EMR, at 4; AG-6; EMR-1; Tr. 22, at 3787). Finally, the Attorney General argues that the Company's regression analysis does not credibly explain future cost of removal and fails to explain 96 percent of the depicted historical relationship (id., citing Exh. AG-6; Attorney General Reply Brief at 24).

The Attorney General further argues that a review of the annual and rolling three-year band historical information provided for Account 367 demonstrates that an increase in negative net salvage to a negative 15 percent is unwarranted at this time (Attorney General Brief at 58, citing Exh. BSG/EMR-2, at 7-19, 7-20. He considers his proposed salvage factor of negative ten percent to be consistent with the Company's historical experience and based on valid analytical tools (Attorney General Brief at 58-59).

(b). Account 380 - Services

The Attorney General argues that the Company's selection of a salvage factor of a negative 170 percent for Account 380 is unsupported by any evidence demonstrating how this rate was selected from the historical values that ranged from a negative 88 percent to a

negative 1,724 percent (id. at 59). Instead, the Attorney General proposes the use of a negative salvage factor of 110 percent (Attorney General Brief at 61; Attorney General Reply Brief at 24).

The Attorney General argues that Bay State used a flawed analytical linear regression and inflation escalation analysis to arrive at its proposed salvage value (Attorney General Brief at 59). The Attorney General considers Bay State's underlying historical data as suspect because they are inconsistent with the significantly different values the Company presented for annual retirements for Bare Steel and Coated/Wrapped Steel Services for the period 1999 through 2004 (id.). According to the Attorney General, while the industry was experiencing a two to three times net salvage relationship between services and mains, the Company claims an approximately 11 times greater relationship here (id. at 60; Attorney General Reply Brief at 25). The Attorney General contends that overall industry averages ranged from negative 45 percent to negative 105 percent, depending on the index used, and that the Company's industry comparison was limited and therefore provided compromised results (Attorney General Brief at 61, citing Exh. AG-6, at 24).

The Attorney General also states that his examination of the four most recent three-year historical bands relied upon by the Company yielded values from a negative 136 percent to a negative 159 percent, and that an analysis of the last ten years of historical data and found that the four years with the highest level of retirement activity yielded a negative 110 percent value (Attorney General Brief at 60, citing Exh. AG-6, at 21). The Attorney General reasons that because Bay State will be experiencing higher levels of retirements in the future as plant approaches its average service life, it is realistic to assume that the net salvage levels

experienced by the larger levels of annual retirements may be more indicative of what can be expected in the future (Attorney General Brief at 60, citing Exh. AG-6, at 21). The Attorney General also argues that the Company's policy of abandoning in place retired services when possible should result in lower levels of cost of removal (Attorney General Brief at 60-61, citing Exh. AG-6, at 24). Finally, the Attorney General asserts that Bay State's witness has, for other companies, proposed significantly lower levels of net salvage than those indicated by the historical data in those cases, but in this case has inconsistently increased his proposed net salvage factors from the historical results even though current salvage levels exhibit smaller negative factors (Attorney General Brief at 61, citing Exh. AG-6, at 24).

iii. Average Service Life/Iowa Curves

(a). Overview

The Attorney General claims that the significant changes in the life characteristics for certain investments in Account 367 that are proposed by Bay State are supported with limited actuarial analysis and rely on unidentified industry data (Attorney General Brief at 61-62, citing Exh. AG-6, at 28). The Attorney General states that, while the Company performed actuarial analyses on its various plant accounts, it had limited meaningful aged data for certain accounts which resulted in less than a full life curve (Attorney General Brief at 62). The Attorney General further asserts that the Company's analysis appears to be based on speculation and flawed fitting of historical data in the curve fitting process (id.).

(b). Account 367.2 - Coated/Wrapped Steel Mains

The Attorney General opposes Bay State's proposed 55-R4 ASL/Curve for Account 367.2, and proposes instead the use of a 74-R4 ASL/Curve (Exh. AG-6, at 41). In

support of his proposed ASL of 74 years, the Attorney General states that a better fit to the actual observed data for this account would support the use of a greater ASL than proposed by Bay State (Attorney General Brief at 64).

The Attorney General contends that, while the Company has attempted to bolster its proposal by claiming that future retirements in this sub account "cannot be greater than 50 years," Bay State offered no evidentiary basis for this assertion, and thus there is no credible evidence on this point (Attorney General Reply Brief at 26). Moreover, the Attorney General notes that the Company did not subject its own analysis for this claimed restriction in developing its proposed ASL for this sub-account (id.). The Attorney General notes that the Company's reliance on industry statistics is misplaced because none of Bay State's mains subaccounts are included in the industry data provided, and that the Company chose not to provide the industry data for those utilities that "experienced service lives" longer than its proposal (id. at 26-27). The Attorney General contends that selective use of industry information in the Company's initial brief does not constitute sufficient support for its proposal (id. at 27).

(c). Account 367.4 - Plastic Mains

The Attorney General opposes Bay State's proposed use of a 55-S2 life-cycle combination curve for Account 367.4 (Attorney General Brief at 63; Attorney General Reply Brief at 26). The Attorney General maintains that his analysis supports the use of a 68-S1.5 life-curve combination (Exh. AG-6, at 34). The Attorney General also observes that other life-curve combinations offer better fits of the data than the Company's proposed life-curve (Attorney General Brief at 63). The Attorney General defends his analysis by arguing

that, despite Bay State's allegations that he plotted the life-curves in a manner that suggests the actual variances appear larger than they really are, the Company does not dispute that his proposed curves offer better fits (Attorney General Reply Brief at 25).

The Attorney General states that the Company's claim that it did not ignore the data beyond 25 years of age is inconsistent with its presentation in Exhibit BSG/EMR-1, at 5-29, which shows that the Company's proposed life-curve combination clearly departs from the actual observed retirements beginning at an approximate age of 25 years (id. at 26). The Attorney General also states that the Company's assertion on brief that it relied on some "additional analysis" that was not part of Mr. Robinson's filed depreciation study as support for its proposed 55-S2 life-curve combination also fails to meet its burden of proof (id.). The Attorney General argues that although the new "additional analysis" by Bay State produced a 41-S2 life-curve combination, the Company failed to explain the difference from its initial life-curve (Attorney General Brief at 63; Attorney General Reply Brief at 26). The Attorney General contends that the Company failed to provide sufficient justification for this analysis and that the Company arbitrarily selected a value from a limited range of select industry data without demonstrating the propriety of those results or its selection (Attorney General Reply Brief at 26).

vi. Other Plant Accounts

The Attorney General claims that the Company's ability to justify the magnitude of its proposed changes to ASLs and net salvage values was severely lacking in many cases (Attorney General Brief at 64, citing Tr. 11, at 1791-1845). The Attorney General states that the Department must base its decision regarding any changes to the ASL and net salvage value

for each plant account on substantial evidence, and not "flimsy claims of judgement" (Attorney General Brief at 64). The Attorney General recommends that the Department scrutinize each of the Company's proposed changes to its accrual rates to ensure that there is substantial evidence to justify the actual magnitude of each change (id. at 65).

Based on his analysis, the Attorney General urges the Department to reject the Company's proposed $28,844,934 depreciation expense and allow depreciation expense of $23,250,682, corresponding to plant as of December 31, 2004 (id. at 54, citing Exh. BSG-JES-1, Sch. JES-7, at 2). In addition, the Attorney General urges that the Department order the Company to perform a fully documented depreciation study that details the basis and justification for net salvage in its next depreciation study (Attorney General Brief at 56).

b. Company

i. Overview

Bay State argues that while the Attorney General chose to examine only two plant accounts, a valid depreciation study must take into consideration all of the various property groups in a utility's plant in service (Company Brief at 137). The Company asserts that an examination of only the two largest property groups does not present a complete picture necessary for the Department to make an informed decision on the depreciation rates of the Company, and, therefore, the Attorney General's recommendations should be rejected (id. at 137-138).

The Company further contests the Attorney General's overall recommendations, arguing that he relies exclusively on selective historical data and gives little or no consideration

to the factors that will affect future net salvage values for various plant accounts (id.). The Company asserts that by doing so, the Attorney General ignores a basic tenet of the Average Remaining Life technique used by its witness, in that the levels of future net salvage must be considered along with historical net salvage when determining depreciation rates (id., citing Exh. BSG/Rebuttal-4, at 4). Moreover, the Company contends that the Department has specifically noted that net salvage values must be determined on a qualitative basis, after taking into account both historic disposal experience and projected cost trends (Company Brief at 148, citing D.T.E. 02-24/25, at 134).

Bay State defends its reliance on judgment in its depreciation study, noting that the Department has long recognized the importance of judgment in a depreciation study and has acknowledged that appropriate depreciation rates cannot be determined merely by statistical analysis of historical data (Company Brief at 148). The Company points out that its witness has more than 30 years of experience preparing depreciation studies, and has recommended depreciation rates based on his judgment and experience after reviewing all of the factors influencing the Company's retirement of its plant in service (id.).

ii. Salvage Factors

(a). Account 367 - Mains

In response to the Attorney General's recommended net salvage rate for Account 367 - Mains of negative ten percent, Bay State contends that the plant accounts for the Company and most other gas companies routinely experience far more negative salvage than positive salvage (id. at 138, citing Exh. AG-6, at 4). Therefore, the Company states, full

recovery of the total cost of an asset will typically be greater than the original cost of the asset (Company Brief at 138).

Bay State considers its salvage forecasts as merely an analytical tool to be used in arriving at the estimates of future net salvage, and should not be used alone to determine the net salvage factors that are recommended (id. at 140, citing Exhs. AG 8-15, AG 8-16, AG 8-18, AG 8-28; DTE 11-15). The Company asserts that the Attorney General gives no consideration to the fact that the future costs of removal for this account will continue to rise, stating that its own forecast analysis using an annual inflation rate of 2.75 percent results in forecasted net salvage for this account of negative 22.58 percent (Company Brief at 139; Exh. BSG/EMR-2, at 7-21). Bay State also argues that future costs of removal for this account will be influenced by many cost increases including those for labor, permitting, street restoration as well as public safety and traffic control costs (id., citing Exhs. AG 8-21; AG 5-18).

In response to the Attorney General's claim that in the past ten years the Company's actual net salvage only exceeded negative 15 percent twice, Bay State contends that in six of those same years, the Company's net salvage exceeded the Attorney General's recommended factor. The Company argues that if all of its historical net salvage data since 1980 are considered, there are many years in which net salvage was far above negative 15 percent (Company Brief at 139, citing Exh. BSG/EMR-2, at 7-19). In regards to the Company's three-year rolling band analysis, Bay State argues that the Attorney General uses only the past nine three-year rolling bands, not the entire history of the account, thus excluding a significant data point where negative net salvage was negative 17.96 percent (Company Brief at 139).

The Company claims that there are a number of errors in the Attorney General's assertion that the Company's model is invalid because of the indicated relationship of cost of removal to retirements against the age of retirements (id. at 140, citing Exh. AG-6, at 14). The Company reasons that the Attorney General's witness used net salvage instead of cost of removal when plotting the property retirement age against the cost of removal, and that the Company's cost of removal data does not permit identification of the cost of removal by the age of plant retired as assumed by the Attorney General (Company Brief at 140, citing Exh. BSG/Rebuttal-4, at 7). The Company asserts that this means there is no direct link between the specific age and dollar amount of a retirement and the corresponding cost of removal in the Company's data and that the Attorney General's witness simply used incorrect data in his analysis and data plotting (Company Brief at 140-141; citing Exh. BSG/Rebuttal-4, at 7-8).

The Company states that for the sixteen companies for which its witness has data, all have negative net salvage percentages for Mains of between negative 15 percent and negative 75 percent (Company Brief at 142, citing Exhs. BSG/Rebuttal-4; BSG/EMR-R3). Moreover, the Company further states that the New England gas companies on the list have negative net salvage percentages of between negative 20 percent and negative 75 percent (id.). The Company also states that the1998 American Gas Association Survey shows a mean average net salvage of negative 36 percent (id.). The Company contends that this data provides additional support for the negative 15 percent net salvage factor as a conservative estimate of salvage values (Company Brief at 142).

(b). Account 380 - Services

Bay State contends that the Attorney General's recommended net salvage value of negative 110 percent is apparently based on the four years during the past decade that have experienced the largest dollar level of retirement activity, and simply ignores the Company's remaining net salvage data for this account (id., citing Exh. BSG/Rebuttal-4, at 13). The Company states that its rolling band analysis for the four most recent bands shows that negative net salvage has been well over negative 110 percent, and in excess of negative 200 percent in some cases for the years dating back to 1980 (id., citing Exhs. BSG/EMR-2, at 7; BSG/Rebuttal-4, at 9). The Company states that its actual historical experience for the account over all years for which data is available shows a net salvage percentage of negative 171.17 percent, and that while its forecasts indicated a net salvage of negative 403.72 percent, the Company elected to limit the negative net salvage to a negative 170 percent (Company Brief at 142-143, citing Exh. BSG/EMR-2, at 7).

Bay State argues that the Attorney General's claim that the net salvage value of negative 1,724 percent reported for 1994 undermines its net salvage data for Services is without merit, because the extremely high negative net salvage is a result of the low retirements for that period (Company Brief at 143, citing Exhs. BSG/EMR-2, at 7-25; AG-6, at 20-21; BSG/Rebuttal-4, at 11-12). The Company maintains that the high negative net salvage indicated in that year was simply caused by the timing of retirements, which is not always synchronized with net salvage transactions recorded in the same accounting period (Company Brief at 144, citing Exh. BSG/Rebuttal-4, at 12).

The Company addresses the Attorney General's claim that the negative net salvage for the Services account is approximately 11 times larger than its recommended net salvage for its

Mains account by claiming that the Attorney General has ignored the fact that the cost of removal for Services will appear to be far greater than that of Mains (Company Brief at 143, citing Exh. BSG/Rebuttal-4, at 11). The Company attributes this to the relatively low original cost of Services in relation to the original cost of Mains (Company Brief at 143; Company Reply Brief at 36).

The Company states that the Attorney General's criticism of its proposed negative net salvage value of 170 percent for the Services account in this proceeding as inconsistent with the witness's recommendations of a negative 55 percent in a Louisville Gas and Electric Company case and a negative 40 percent in a Kansas Gas Services Company case has no merit (Company Brief at 144). The Company asserts that in those cases the average service lives for the Services account were approximately 50 to 60 percent of the length of the average service lives being recommended for Bay State in this case and, therefore, it is to be expected that the negative net salvage figures in those cases would be substantially less negative than what is required for Bay State (id., citing Exh. BSG/Rebuttal-4, at 12-13). The Company further asserts that its recommended net salvage factor for this account is consistent with the net salvage levels used in depreciation studies of other New England gas companies (Company Brief at 144, citing Exhs. BSG/Rebuttal-4; BSG/EMR-R3).

Finally, the Company contends that in light of the support in the record for Mr. Robinson's recommended net salvage factors, there is no basis for the Attorney General's request that the Department require a more detailed justification of the net salvage factors in the Company's next depreciation study (Company Brief at 145).

iii. Average Service Lives/Iowa Curves

(a). Account 367.4 - Plastic Mains

Bay State contends that the Attorney General plotted his ASL data for this account in a manner that makes the variances between his recommendation and the Company's proposal appear far larger than they actually are (id.). Moreover, the Company claims that the Attorney General ignored data beyond 25 years of age when determining his proposed ASL of 68 years (id.). The Company argues that examination of this additional data is necessary for this account because of the dramatic change in the survivor curve which occurred between the ages of 25 and 26 (id., citing Exhs. BSG/Rebuttal-4, at 14-16; AG-6, at 32).

The Company maintains that significant levels of plastic mains retirements have occurred as a result of a variety of causes, not all of which are physical, and such retirements will continue to occur at increasing levels in the future (Company Brief at 145-146, citing Exh. BSG/Rebuttal-4, at 15-16). The Company contends that its proposed ASL of 55 years is confirmed by the results of an American Gas Association and Edison Electric Institute industry depreciation survey indicating a mean ASL for the overall industry Account 376 of 55 years, and is conservative in relation to the results found in other gas industry depreciation studies, including some in New England (Company Brief at 146-147, citing Exhs. BSG/Rebuttal-4, at 17; EMR-R3).

(b). Account 367.2 - Coated/Wrapped Steel Mains

Bay State contends that the Attorney General misinterpreted the historical data and the likely effect of future activity on the ASL for this property category when recommending the use of an 74-R4 life-curve for Account 367.2-Coated/Wrapped Steel Mains (Company Brief

at 147; Exh. AG-6, at 41). The Company asserts that the Attorney General simply did not perform the kind of detailed analysis of the data that should have been performed (Company Brief at 147). According to Bay State, the Attorney General has failed to consider that the oldest vintage property in this account dates back to 1953, and that because future retirements cannot currently occur at ages greater than 50 years, the resulting ASL for this account cannot be greater than 50 years (id., citing Exh. BSG/Rebuttal 4, at 18; Company Reply Brief at 36). The Company further asserts that its depreciation parameters for Account 367.2 are amply supported by the historical data, are appropriate for this property group and are based on a 55-year ASL that is conservative in relation to ASLs used by other companies for this account (Company Brief at 148, citing Exh. BSG/Rebuttal-4, at 18-19).

3. Analysis and Findings

a. Standard of Review

Depreciation expense allows a company to recover its capital investments in a timely and equitable fashion over the service lives of the investments. D.T.E. 98-51, at 75; D.P.U. 96-50 (Phase I) at 104; Milford Water Company, D.P.U. 84-135, at 23 (1985); Boston Edison Company, D.P.U. 1350, at 97 (1983). Depreciation studies rely not only on statistical analysis but also on the judgment and expertise of the preparer. The Department has held that when a witness reaches a conclusion about a depreciation study which is at variance with that witness's engineering and statistical analysis, the Department will not accept such a conclusion absent sufficient justification on the record for such a departure. D.P.U. 92-250, at 64; D.P.U. 89-114/90-331/91-80 Phase One at 54-55; D.P.U. 88-135/151, at 37; D.T.E. 01-56, at 93. It is also necessary to go beyond the numbers presented in a depreciation study and

consider the underlying physical assets. D.P.U. 92-250, at 64; D.P.U. 905, at 13-15; Massachusetts Electric Company, D.P.U. 200, at 21 (1980).

b. Use of Judgment

The Attorney General contends that Bay State's expert depreciation witness, in many cases, has not provided sufficient justification and evidence to support the magnitude of his proposed accrual rate changes (Attorney General Brief at 64-65; Attorney General Reply Brief at 21-22). The Department recognizes that the determination of depreciation accrual rates requires both statistical analysis and the application of the preparer's judgment and expertise. D.T.E. 02-24/25, at 132. Because depreciation studies rely by their nature on examining historic performance to assess future events, a degree of subjectivity is inevitable.[145] Nevertheless, the product of a depreciation study consists of specific accrual rates to be applied to specific accounts' balances associated with depreciable property. A mere assertion that judgment and experience warrant a particular conclusion, i.e., what the Attorney General characterizes on brief as a doctrine of ipse dixit, does not constitute evidence. See Eastern Edison Company, D.P.U. 243, at 16-17 (1980); D.P.U. 200, at 20-21; Lowell Gas Company, D.P.U. 19037, at 23 (1977).

It thus follows that the reviewer of a depreciation study must be able to determine, preferably through the direct filing, and at least in the form of comprehensive responses to well-prepared discovery, the reasons why the preparer of the study chose one particular

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[145] This is especially relevant in the calculation of net salvage factors, where the cost to demolish or retire facilities cannot be known until the actual event occurs. D.P.U. 92-250, at 66; Boston Edison Company, D.P.U. 1720, at 44 (1984); D.P.U. 1350, at 109.

life-span curve or salvage value over another. The Department will continue to look to the expert witness for interpretation of its statistical analyses, but will consider expert testimony and evidence to the contrary, and expect sufficient justification on the record for any variances resulting from the engineering and statistical analyses. D.P.U. 89-114/90-331/91-80 Phase One at 54-55. To the extent a depreciation study provides a clear and comprehensive explanation of the factors that went into the selection of accrual rates, such an approach will facilitate Department and intervener review.[146]

c. Account 365 - Rights of Way

Bay State proposes a depreciation accrual rate of 2.18 percent for this account (Exh. BSG/EMR-2, § 4, at 5). Rights of way constitute interests in land acquired for the purpose of constructing transmission and distribution mains, and can be for either a limited term or a grant in perpetuity (Tr. 11, at 1860-1861). Even if the mains which run through the rights of way are fully depreciated, there is no reason to assume that the line will be retired, or that the associated rights of way necessarily have a limited life. Therefore, there is no basis on which to depreciate rights of way. D.P.U. 92-111, at 122-123; Western Massachusetts Electric Company, D.P.U. 558, at 28-29 (1981); The Berkshire Gas Company, D.P.U. 19580, at 16 (1978); Western Massachusetts Electric Company, D.P.U. 18252, at 12 (1975). Accordingly, the Department will reduce the Company's proposed depreciation expense by

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[146] Bay State faults the Attorney General for confining his proposed adjustments to Accounts 367 and 380, and not performing a full depreciation study (Company Brief at 136). The Attorney General is free to shape his litigation strategy in whatever manner he desire, including deciding where to place his emphasis in reviewing the Company's filing.

$1,723. The Company is directed to cease booking depreciation expense against Account 365.[147]

d. Account 367.2 - Coated/Wrapped Steel Mains

The Company proposes an ASL/Curve of 55-R4 and a salvage value of negative 15 percent for this account, producing a depreciation rate of 2.53 percent (Exh. BSG/EMR-2, § 4, at 10). The Attorney General asserts that the Company used selective industry information in support of its proposed accrual rate (Attorney General Reply Brief at 27). The Company's retirement experience indicates an ASL of 52.5 years and average remaining life of 33.03 years for this account (Exh. BSG/EMR-2, § 6, at 33, § 7, at 19-21). While the Attorney General's analysis suggested that an ASL of 74 years provided a better fit with the statistical data, the Attorney General's analysis gave limited weight to retirement data points beyond 53 years of age (Exhs. AG-6, at 36-37; BSG/Rebuttal 4, at 18). This limited reliance on these older data points serves to distort the curve fit and skew the results of the analysis. The Company's selection of a 55-R4 ASL/Curve is consistent with the results of its statistical analysis and industry experience (Exhs. BSG/EMR-2; EMR-R3).

Concerning the proposed salvage factor of negative 15 percent, the evidence demonstrates that Account 367 will continue to experience significant levels of retirements in future years from a variety of causes, including physical obsolescence and construction activity (Exhs. BSG/EMR-1, at 22-23; BSG/EMR-2, § 4, at 10; AG 8-32). In view of this salvage

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[147] The Company was directed to cease booking depreciation expense against this account in D.P.U. 92-111, at 123. The Department expects that we will not be required to issue this directive to the Company a third time.

history for Account 367, a negative 15 percent salvage factor is reasonable (Exh. BSG/EMR-2, § 7, at 19-21).

Therefore, the Department finds that the Company has properly interpreted the results of its statistical analyses. Accordingly, we will accept the proposed accrual rate of 2.53 percent for Account 367.2.

e. Account 367.4 - Plastic Mains

Bay State proposes an ASL/Curve of 55-S2 and a salvage value of negative 15 percent for this account, producing a depreciation rate of 2.17 percent (Exh. BSG/EMR-2, § 4, at 10). The Attorney General claims that the Company has failed sufficiently to analyze and support its proposal (Attorney General Reply Brief at 26). The Company's statistical analysis demonstrates an ASL for this account of 52.5 years and average remaining life of 46.29 years (Exh. BSG/EMR-2, § 6, at 37, § 7, at 21). While the Attorney General's analysis suggested that an ASL of 68 years provided a better fit with the statistical data, the Attorney General's analysis was confined to data no greater than 25 years old (Exhs. AG-6, at 31-32; BSG/Rebuttal 4, at 14-15). In contrast, the Company's analysis took into consideration all of the available historic data (Exh. BSG/Rebuttal-4, at 15-16). Moreover, most plastic main retirements occurred in the years 1978 and thereafter, suggesting that any earlier problems with plastic mains as referenced by the Attorney General have not had a significant effect on this account (id. at 15). Therefore, the Department finds that the Company has sufficiently supported its proposed 55-S2 ASL/Curve (Exhs. EMR-R3; BSG/EMR-2, § 4, at 10).

Concerning the proposed salvage factor of negative 15 percent, the evidence demonstrates that Account 367 will continue to experience significant levels of retirements in

future years from a variety of causes, including physical obsolescence and construction activity (Exhs. BSG/EMR-1, at 22-23; BSG/EMR-2, § 4, at 10; AG 8-32). In view of this salvage history for Account 367, a negative 15 percent salvage factor is reasonable (Exh. BSG/EMR-2, § 7, at 19-21).

Therefore, the Department finds that the Company has properly interpreted the results of its statistical analyses. Accordingly, we will accept the proposed accrual rate of 2.17 percent for Account 367.4.

f. Other Subaccounts to Account 367 - Mains

The Company proposes to decrease the net salvage factors from a negative ten percent to negative 15 percent for: (1) Account 367.1 - Cast Iron Mains; (2) Account 367.3 - Steel Mains - Bare; (3) Account 367.5- Joint Seals; and (4) Account 367.6 - Cathodic Protection, resulting in depreciation rates ranging from 2.41 percent to 7.55 percent (Exh. BSG/EMR-2, § 2, at 3, § 4, at 10). While the Attorney General proposes a net salvage value of negative 10 percent for these accounts, the Company's historical net salvage experience supports a forecast negative net salvage factor of 22.58 percent (Exh. BSG/EMR-2, § 7, at 21). A review of the retirement data indicates negative net salvage factor of greater than negative 15 percent for thirteen years between 1980 and 2003 (id. at 19). In addition, out of 23 years of data covered by the Company's analysis, only five years show a negative salvage factor of less than ten percent, with the smallest negative net salvage value being a negative 3.64 percent occurring in 1995 (id.). Although negative net salvage factors decreased during the mid-1990s, more recent experience indicates that this earlier trend has reversed (id. at 20). The Attorney General points to the Company's the witness's unfamiliarity with the R-squared

statistic. This fact does not serve to undermine the credibility of the witness or his ability to interpret the Company's statistical analysis because R-squared statistic is not the sole determining factor in the Company's regression analysis. D.P.U. 89-114/90-331/91-80 (Phase One) at 52. We agree that future costs of removal for this account will likely continue to rise because of cost increases associated with labor, permitting, street restoration, public safety, and traffic control costs (Exhs. AG 8-21; AG 5-18). Therefore, the Department finds that the Company has properly interpreted the results of its statistical analyses and accepts the proposed accrual rates for the remaining subaccounts to Account 367.

g. Account 380 - Services

The Company proposes the use of material-specific ASL/Curves for the four subaccounts contained in Account 380, and decreasing the net salvage factor from a negative 140 percent to negative 170 percent, producing a proposed composite accrual rate of 5.08 percent (Exhs. BSG/EMR-2, § 2, at 3; BSG/EMR-2, § 4, at 16). The Attorney General recommends a negative 110 percent net salvage value for this account (Attorney General Reply Brief at 24).

The Attorney General's analysis did not take into consideration all of Bay State's net salvage data for this account (Exh. AG-6, at 16-25). In contrast, the Company used all of its historic data when making its recommendations for this account. Bay State's historical net salvage experience shows that the Company routinely experienced negative net salvage values of negative 170 percent and higher (Exh. BSG/EMR-2, § 7, at 25). In view of this salvage history for Account 380, a negative 170 percent salvage factor is reasonable (id. at 25-27).

Therefore, the Department finds that the Company has properly interpreted the results of its statistical analyses and accepts the proposed accrual rate for Account 380.

h. Conclusion

Based on this analysis, the Department has accepted the results of the Company's depreciation study with the exception of Account 365, Rights of Way. In addition, the Department has excluded from rate base $92,962 in plastic mains associated with the Palmer/Mount Dumpling project. See Section IV.A.3, above. The Department has also removed $106,205 from the Company's completed construction not yet classified to account for retirements not yet booked. See Section IV.D.3, above. Consistent with this ratemaking treatment, corresponding reductions to depreciation expense are necessary. D.P.U. 88-67 (Phase I) at 160-161. In order to determine the appropriate depreciation expense adjustment for Bay State, the Department has: (1) multiplied $79,051 by 2.18 percent to eliminate depreciation expense associated with rights of way; (2) multiplied $92,962 by 2.17 percent to eliminate depreciation expense associated with the Palmer/Mount Dumpling project; and (3) multiplied $106,205 by a composite accrual rate for Account 367 of 2.79 percent[148] to eliminate depreciation expense on unrecorded plant retirements. This results in a decrease of $6,703 to the Company's depreciation expense. Accordingly, the Department will reduce the Company's proposed cost of service by $6,703.

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[148] A composite rate was applied to these retirements, because the retired plant is not broken down by type of main (Exh. BSG/JES-1, Sch. JES-7, at 3 (Rev.); RR-DTE-36).

VI. CAPITAL STRUCTURE AND RATE OF RETURN

A. Capital Structure

1. Introduction

At the end of the test year, Bay State's capital structure consisted of $178,500,000 in long-term debt and $566,347,650 in common equity (Exh. BSG/PRM-2, Sch. PRM-5). This represents a capitalization consisting of 23.96 percent debt and 76.04 percent common equity (id.). The Company proposed a number of adjustments to its capital structure, resulting in a capitalization consisting of 46.05 percent long-term debt and 53.95 percent common equity (Exhs. BSG/PRM-1, at 21; BSG/PRM-2, Sch. 5). First, Bay State removed from its common equity balance $117,973,478 representing its investment in its subsidiaries Northern Utilities and Bay State GP (Exhs. BSG/PRM-1, at 20; BSG/PRM-2, Sch. 5; RR-DTE-51, at 2). Second, the Company removed from its common equity balance $233,433,469 representing unamortized goodwill balances (Exhs. BSG/PRM-1, at 21; BSG/PRM-2, Sch. 5; RR-DTE-51, at 2). Third, Bay State reduced its debt balance by $10,000,000 to recognize the maturity of its 6.58 Percent Series notes, which occurred on June 21, 2005 (Exhs. BSG/PRM-1, at 20; BSG/PRM-2, Sch. 5; RR-DTE-51, at 2). Finally, the Company included $15,000,000 in long-term notes authorized by the Department in Bay State Gas Company, D.T.E. 04-80 (2004) (Tr. 7, at 1157-1160; Exhs. BSG/PRM-1, at 20; BSG/PRM-2, Sch. 5; RR-DTE-51, at 2).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that Bay State is maintaining a large balance of short-term debt that is being used to permanently finance the Company's investments (Attorney General Brief at 96, citing Exh. BSG-AG 1-16; Tr. 17, at 2833-2836). The Attorney General asserts that of the Company's total average short-term debt balance during the test year of $186,343,535, $33,131,681 is being used to finance gas purchases, leaving $153,211,854 to be used to meet capital requirements (Attorney General Initial Brief at 97, citing Tr. 17, at 2833-2836; Exhs. BSG/JES-1, Sch. JES-1; BSG/JES-2, Sch. WC-4; BSG-AG-1-16; RR-DTE-118).

The Attorney General contends that the Company is using all sources of capital including short-term debt to fund its business operations (Attorney General Reply Brief at 45, citing 2004 Annual Return to the Department at 8). The Attorney General reasons that the proceeds of Bay State's short-term borrowing are fungible and indistinguishable from cash derived from long-term financings, and should therefore be included in the Company's capital structure (Attorney General Reply Brief at 45). The Attorney General argues that the Company's claims that short-term debt is not used to finance rate base are unsupported, and that in the absence of contrary evidence, the Department must assume that the monies from the different outstanding securities are used for all possible business purposes (id., citing Town of Hingham v. Department of Telecommunications and Energy, 433 Mass. 198, 213-214 (2001)).

The Attorney General contends that the Department includes short-term debt in the capital structure when it is a significant component of the utility's finances, in order to protect

ratepayers from the effects of excessive rates of return (Attorney General Brief at 95-96, citing Blackstone Gas Company, D.T.E. 01-50 (2001); Assabet Water Company, D.P.U. 95-92, at 33 (1996); Wylde Wood Water Works, D.P.U. 86- 93 (1987); Blackstone Gas Company, D.P.U. 1135, at 4 (1982)). According to the Attorney General, although these utilities are small in comparison to Bay State, the Company fails to explain the relevance of the size of the utility (Attorney General Reply Brief at 46).

The Attorney General maintains that including the Company's short-term debt in its capital structure would produce capitalization ratios that are within the bounds of the average distribution company for Standard & Poor's "A" and "BBB" rated companies (id. at 44, citing Exh. BSG-AG-1-16, Att. 2.31). The Attorney General asserts that the Company's claim that NiSource does not control essentially all of the Company's outstanding capital is contrary to evidence in the record (Attorney General Reply Brief at 44). In fact, the Attorney General states that NiSource controls more than 90 percent of the outstanding securities, and that the percentage is increasing (id., citing Exh. BSG/PRM-5). The Attorney General alleges that the existing long-term debt that the Company has on its books is simply the debt remaining from the time prior to its acquisition by NiSource (Attorney General Reply Brief at 44-45). The Attorney General notes that Bay State no longer issues any securities notes, bonds or stock to the market (id. at 45 citing, e.g., D.T.E. 04-80; Bay State Gas Company, D.T.E. 03-65 (2003); Bay State Gas Company, D.T.E. 02-73 (2002)).

The Attorney General argues that failure to include the Company's short-term debt in its capital structure would result in an unfair transfer of wealth to Bay State's shareholders (Attorney General Brief at 97). Although the Company claims on brief that it will double

recover its carrying costs on gas expense if short-term debt is included in the capital structure, the Attorney General maintains that his proposed adjustment would eliminate short-term debt associated with purchased gas working capital needs (Attorney General Reply Brief at 45). The Attorney General points out that this adjustment was in response to a Department record request (id. at 45-46, citing RR-DTE-118).

b. Company

Bay State argues that the Attorney General's proposed capital structure totals $579,784,283, which is far larger than the Company's rate base (Company Brief at 192, citing Exh. BSG-AG-1- 16, Att. 1, at 1). The Company asserts that it would be inappropriate to include short-term debt in the capital structure of Bay State, because short-term debt is not used to finance Bay State's rate base (Company Brief at 192; Company Reply Brief at 47-48). Bay State maintains that its proposed total pro forma capitalization, consisting of long-term debt and common equity, is $398,440,703 and closely matches its test year rate base of $397,095,644 (Company Brief at 192-193, citing Tr. 22, at 3746-47; Exhs. BSG/JES-1, Sch. JES-1; BSG/PRM-2, Sch. PRM-5;; RR-DTE-51, at 2).[149]

The Company states that the Attorney General proposes a capital structure that is larger than the Company's rate base by approximately $182 million (Company Brief at 193, citing RR-DTE-118). The Company also states, however, that the Attorney General uses another calculation where proposed capitalization is $153 million greater than the Company's rate base (id.). The Company asserts that if the Department accepted a rate base for Bay State that

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[149] Upon reply brief and in final Company exhibits and schedules, the Company's rate base is $397,099,434 (Exh. BSG/JES-1, Sch. 16, at 4).

matched the total capitalization as proposed by the Attorney General, the Company's required return on rate base would be significantly larger than what has been proposed by the Company (Company Brief at 193).

Bay State disputes the Attorney General's argument concerning Standard and Poor's debt ratios, contending there is no evidence that investors use this particular report in their investment decisions, and argues that the average year-end debt ratio for the comparison group approximates the Company's proposed debt ratio (Company Reply Brief at 47; citing Exh. BSG/Rebuttal-3A; RR-DTE-51 (Supp.)). The Company states that the Attorney General's reliance on a number of past Department orders supporting the inclusion of short-term debt in capitalization are inapposite to Bay State, because these cases involved small utilities where the Department determined that a hypothetical capital structure was appropriate (Company Brief at 193-194).

Bay State contends that its short-term debt is used to finance purchased gas costs, as well as gas storage costs, and that the cost of the associated short-term debt is already recovered in Bay State's cost of gas adjustment clause (id. at 193, citing Exh. AG-1-2 (Annual Return for 2004); Tr., at 3747-48). The Company maintains that if the Attorney General's proposal were adopted and short term debt were included in the capital structure for base rates, the Company would recover short-term debt costs twice (Company Brief at 193).

3. Analysis and Findings

A company's capital structure typically consists of long-term debt, preferred stock, and common equity. D.T.E. 01-56, at 97; Pinehills Water Company, D.T.E. 01-42, at 17-18 (2001); Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 62 (2001);

D.P.U. 87-228, at 22. The ratio of each capital structure component to the total capital structure is used to weight the cost (or return) of each capital structure component to derive a weighted average cost of capital ("WACC"). The WACC is used to calculate the return on rate base for calculating the appropriate debt service and profits for the company to be included in its revenue requirements. D.T.E. 01-42, at 18; South Egremont Water Company, D.P.U. 86-149, at 5 (1986).

As a general policy, the Department does not include short-term debt in capital structure because it is traditionally used to finance construction. However, on occasion, the Department has included short-term debt when it is demonstrated that the utility's short-term debt plays the role of long-term debt. D.P.U. 86-86, at 22-23; D.P.U. 323, at 8.

The Department has recognized that short-term debt as a percentage of total debt has increased dramatically for utilities across the Commonwealth in recent years. D.T.E. 02-24/25, at 212. If companies finance too much of their operations through short-term debt, access to capital for construction is limited because lines of credit that would otherwise be used to finance the construction of new plant become exhausted. Also, volatility in short-term interest rates would result in large additional interest expenditures that would adversely affect the utility's net income. Id.

Bay State's short-term debt balances have fluctuated in recent years, ranging between $116.8 million in 1999 to $218.9 million in 2002 (Exh. AG 1-2 (1999 through 2004 Annual Returns to the Department) at 32). During the test year, the Company's short-term debt ranged between $157.6 million and $215.9 million (Exh. AG 1-6). While the level of short-term debt is significant for a company of Bay State's size, this degree of fluctuation does

not indicate a stable capitalization, as would typically be seen with long-term debt. The Company's capital structure of about $398 million approximates its proposed rate base of approximately $397 million (Exhs. BSG/JES-1, Sch. JES-1 at 1; BSG/PRM-2, Sch. PRM-5). This coverage indicates that the Company has not been relying on short-term debt to finance its rate base, nor has the Department identified any unusual items in the Company's cash flow statements that would suggest Bay State is using short-term debt in the manner claimed by the Attorney General (Exh. AG 1-6, Att. AG 1-6(2)(a)).

Although inclusion of short-term debt may produce a capitalization ratio consistent with Standard and Poor's criteria for credit rating purposes, the Company's proposed capitalization ratio of 46.05 percent debt and 53.95 percent common equity is not so far out of line with utility practice as to warrant the imputation of a hypothetical debt ratio. Nantucket Electric Company, D.P.U. 91-106/138, at 95-98 (1991), cf. D.T.E. 03-40, at 315, 325 (removal of goodwill and sinking fund payment percent produced debt ratio of 32.01 percent warranted imputation of hypothetical capital structure).

While the Department will consider including an appropriate percentage of short-term debt in a company's capital structure where there is a sufficient showing that it is being used to finance rate base assets, the record does not support a conclusion that Bay State is using short-term debt in place of long-term debt.[150] Thus, the Department will not include any of the

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[150] The Department has recognized that inclusion of short-term debt in a company's capital structure may require accompanying modifications to the Department's regulatory policies involving construction work in progress and allowance for funds used during construction, and a reevaluation of the risk component of a utility's return on equity. Therefore, the costs and benefits of including short-term debt in a company's capital

(continued…)

Company's short-term debt in its capital structure. The Company's proposed adjustments to its debt capitalization are known and measurable. D.P.U. 90-121, at 156-157. Additionally, the Company's proposed equity adjustments for goodwill and equity investment in affiliates are consistent with Department policy. D.T.E. 03-40, at 320-324; Colonial Gas Company, D.P.U. 84-94, at 51-42 (1984). Therefore, the Department will use a capital structure consisting of 46.05 percent long-term debt and 53.95 percent common equity to determine the Company's revenue requirement.

B. Rate of Return on Equity

1. Introduction

The Company requests a 11.5 percent return on equity ("ROE"), and proposes a 9.02 percent weighted cost of capital (RR-DTE-51). To determine its cost of equity, the Company sponsored the testimony and analysis of Mr. Paul R. Moul. Mr. Moul used four measures of the cost of equity: the Discounted Cash Flow ("DCF"), the Risk Premium ("RP"), the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") models. Each model was analyzed using average financial and market data from a proxy group of five natural gas companies determined by the Company to have similar operations as Bay State (Exh. BSG/PRM-1, at 3-5). The Company assessed the results of each model and determined that the DCF approach provided atypical results of 10.21 percent, compared with 11.75 percent from the RP, 12.01 percent from CAPM, and 13.70 percent from CE analyses

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[150] (…continued)
structure must be carefully assessed. D.T.E. 02-24/25, at 213 n.90.

(id. at 3-6). Therefore, the Company placed less weight on the results of the DCF model, and concluded that a return of 11.5 percent was reasonable.

Bay State is a wholly-owned subsidiary of NiSource, and accordingly, there are no market data for the Company's common stock, and consequently, no means to assess directly investor expectations of the Company's required return. Therefore, the Company provided an analysis of five gas distribution companies it considers to be of generally comparable risk to Bay State ("Gas Group") (id. at 2-3, 13).[151] The Gas Group includes AGL Resources, Inc., New Jersey Resources Corp., Piedmont Natural Gas Co., South Jersey Industries, Inc., and WGL Holdings, Inc. (Exh. BSG/PRM-2, Sch. 3, at 2). In addition, the Company provided an analysis of the fundamental risk of Bay State compared to the Gas Group and the Standard and Poor's ("S&P") Public Utility Index (Exh. BSG/PRM-1, at 13).[152]

The Attorney General presented a direct case through the testimony of Mr. Timothy Newhard, financial analyst for the Attorney General (Exh. AG-8, at 1). The Attorney General performed one- and two-step DCF analyses, resulting in a recommended ROE in the range of 8.66 to 9.21 percent (id. at 16). However, because the Attorney General considers the

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151 Bay State's selection criteria included companies that (1) are engaged in similar business lines, (2) have publicly-traded common stock that is listed on the New York Stock Exchange, (3) are contained in the Value Line investment survey in the industry group entitled "natural gas distribution," (4) have operations in the Northeastern, Great Lakes and Southeastern regions of the U.S., (5) have not cut or omitted their dividend, (6) have at least 80 percent of their assets represented by gas operations, and (7) are not currently the target of a merger or acquisition (Exh. BSG/PRM-1, at 13-14).

152 The S&P Public Utility Index is a market capitalization-weighted index of natural gas and electric companies (Exhs. BSG/PRM-1 at 13; BSG/PRM-2, Sch. 4, at 1-3).

Company to be less risky than the Gas Group, he recommends an ROE at the low end of the range of possible values, i.e., 8.66 percent (id. at 18).

Local 273 also provided testimony on the appropriate ROE for the Company (Exh. UWUA-4, at 62-64). Local 273 states that Bay State management performance was poor, and that the Company's ROE should be lowered as a penalty for such performance (id.).[153]

2. Company's Proposal

a. Discounted Cash Flow Analysis

The DCF model is predicated on the theory that a stock's price represents the present value of all investor expected cash flows from the stock, discounted at an appropriate risk-adjusted rate of return. By substituting the value of the common stock, the discounted rate of return can be determined (Exh. BSG/PRM-1, at 23-38). The DCF model is represented by the following equation where D_1 is the expected dividend to be paid in the next period (period one), P_0 is the current market price of the stock, and g is the expected growth rate:

$$ROE = D_1 / P_0 + g$$

(id. at 38).

As the dividend yield, the Company calculated the average yield for the Gas Group for the six-month period August, 2004 through January, 2005 at 3.82 percent (id. at 25-26; Exh. BSG/PRM-1, App. E at 6-8). As the growth rate, the Company analyzed the five-year and ten-year historical growth rates and the five-year forecast growth rates in earnings-per-

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153 On brief, Local 273 proposed a 50-basis point reduction from the Attorney General's proposed ROE (UWUA Brief at 42).

share, dividends-per-share, book value-per-share, and cash flow-per-share for the Gas Group (Exh. BSG/PRM-1, at 30). Relying on the forecasts of earnings-per-share, the Company arrived at a prospective growth rate of 5.75 percent (id. at 30-34). Applying the yield and growth inputs, the DCF analysis determined that the ROE is 9.57 percent (id. at 34-36). The Company then adjusted the DCF-determined ROE for financial risk associated with the book value of capitalization through a "leverage adjustment" of 0.64 percent, arriving at a final DCF cost rate of 10.21 percent (id. at 38; Exh. BSG/PRM-1, App. E at 14).[154]

b. Risk Premium Analysis

Risk premium analyses are based on the assumption that equity securities are riskier than debt and, therefore, equity investors require a higher ROE. D.T.E. 02-24/25, at 217. The risk premium model is represented by the following equation where i is the long-term bond yield and RP is the equity risk premium:

$$ROE = i + RP$$

(Exh. BSG/PRM-1, at 44).

To arrive at a long-term bond yield of 7.00 percent, Bay State relied on historical interest rates and forecast yields on A-rated public utility bonds (id. at 38-39). The Company determined forecast yields on A-rated public utility bonds by using the Blue Chip Financial Forecasts ("Blue Chip") (id. at 40-41).

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[154] The proposed leverage adjustment is intended to recognize the financial risk difference between the market value equity ratio and the book value equity ratio (Exh. BSG/PRM-1, at 37).

To calculate the equity risk premium, the Company calculated a "risk rate differential" by comparing the market returns on utility stocks (using the S&P Public Utility Index) and the market returns on utility bonds (id. at 41-42). The Company measured the central tendency of historical returns over several holding periods and arrived at a common equity risk premium of 4.95 percent (id. at 43). However, due to the risk differences between the S&P Public Utilities and the Gas Group, in Mr. Moul's judgment, the appropriate risk premium to use for the Company was 4.75 percent (id. at 43-44). Based on these inputs, the Company arrived at a ROE of 11.75 percent using the risk premium approach (id. at 44).

c. Capital Asset Pricing Model

The CAPM is a more elaborate version of the risk premium analysis that attempts to recognize the riskiness of a utility's common stock in relation to the overall riskiness of the market. The CAPM considers an adjustment for market-related or systematic risk, represented by beta, the risk-free rate of return, and a market return (id. at 45; Exh. BSG/PRM-1, App. H at 2). The CAPM formula is as follows, where R_f is the risk-free rate, β is the beta, expressed as a ratio of a firm's return relative to that of the overall market, and R_m is the market return:

$$ROE = R_f + \beta (R_m - R_f)$$

(Exh. BSG/PRM-1, at 48).

The Company also performed a CAPM analysis for the Gas Group. Using both historical and forecast yields on long-term Treasury bonds as a proxy, the Company applied 6.00 percent as the risk-free rate (id. at 46-47). The Company derived an average 0.72 beta for the Gas Group using data from the Value Line Investment Survey (id. at 45). Using a formula that "un-leverages" the Value Line betas and then "re-leverages" them for common

equity ratios using book values instead of market values, the Company adjusted the Gas Group beta to 0.85 (id. at 46). To determine the market risk premium of 6.00 percent (R_m - R_f), the Company averaged an historical market performance of 6.60 percent with the Value Line forecast of 5.39 percent (id. at 47). Using these values (6.00 percent risk free rate, and 6.00 percent market premium multiplied by the 0.85 leverage adjusted beta), the Company derived a 11.10 percent ROE using the CAPM (id. at 48). The Company then adjusted this ROE by 0.91 percent to account for the relative market capitalization of the Gas Group, arriving at a 12.01 percent ROE (id.).

d. Comparable Earnings Approach

The comparable earnings approach relies on historical and forecast returns for non-regulated companies as a measure of the regulated utility's ROE. Parameters identifying a group of non-regulated companies with risk characteristics similar to those of the utility being examined are selected, including financial strength, price stability, and market performance (Exh. BSG/PRM-1, App. I at 1-3).

In order to implement the Comparable earnings approach, the Company selected non-regulated companies from Value Line Investment Survey for Windows, using six categories of comparability to reflect the risk of the Gas Group (Exh. BSG/PRM-1, at 51). The criteria include timeliness rank (a rank for a stock's probable relative market performance in the year ahead), safety rank (a measure of potential risk associated with individual common stocks rather than large diversified portfolios), financial strength (relative financial strength of a company relative to other companies based on measures of financial leverage, business risk, and company size as well as the judgment of Value Line's analysts), price stability (based on a

index of weekly percent changes in the price of a stock over the last five years), value line betas (the sensitivity of a stock's price to overall NYMEX fluctuations), and technical rank (a prediction of relative price movement, primarily over the next three to six months; a function of price action relative to all stocks followed by Value Line) (BSG/PRM-1, at 51).

In Schedule PRM-13 of Exhibit BSG/PRM-2, Mr. Moul lists the group of companies included in this comparison group (Exhs. BSG/PRM-1, at 51; BSG/PRM-1, App. I, at 1-3). The Company identified 32 non-utility companies it considered to have comparable risks to Bay State (Exh. BSG/PRM-2, Sch. PRM-13, at 1-2).[155] Based on the results of this analysis, the ROE for non-utility companies comparable to Bay State is 13.70 percent (Exh. BSG/PRM-1, at 52).

3. Attorney General's Proposal

The Attorney General sponsored the testimony of Mr. Newhard on return on equity. Mr. Newhard chose a group of companies, the same group as that used by Mr. Moul (the Gas Group) that he deemed comparable in investment risk to Bay State and performed his cost of equity analyses on this group of companies to determine the cost of equity for the Company (Exh. AG-8, at 5-6). As a result of his analyses in this case, Mr. Newhard determined that the cost of common equity for Bay State is 8.66 percent (id. at 1).

Mr. Newhard provided two stock market based approaches to estimate the cost of equity for the Company and for NiSource, as a benchmark for his other analyses (id. at 1, 5).

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155 The companies comprising the comparison group for this analysis include those operating in such industries as food products, metals, grocery, husehold products, and many more (Exh. BSG/PRM-2, Sch. 13, at 1).

He refers to one approach as the Growth Rate Discounted Cash Flow Analysis ("One Step DCF") and the other as a Two-Step Discount Cash Flow Analysis ("Two Step DCF") (id. at 3).

Mr. Newhard's One Step DCF is a similar analysis to that performed by Mr. Moul. However, the values for the variables chosen by Mr. Newhard vary greatly from those chosen by Mr. Moul. For dividend yield, Mr. Newhard provided the most recent twelve months of dividend yield information through June of 2005 for this Gas Group's common stock in his response to Exhibit AG-8, Schedule 2 (Exh. BSG-AG-1-41). From this information, the Attorney General asserts that the most recent six-month dividend yield average is 3.57 percent, while the most recent twelve-month average is 3.67 percent (Exh. AG-8, Sch. 2). Based on these yields, the Attorney General states that a 3.62 percent dividend yield adjusted for the growth rate discussed below is an appropriate basis for the Department to use in its analysis of the DCF model (Exh. AG-8, at 8-9).

For the Company's growth rate, Mr. Newhard states that because growth (or reduction) in dividends per share which result from an increase (or decrease) in the payout ratio cannot be continuous, a simple measure of the historical growth rate of dividends per share could lead to an incorrect estimate of the expected long-run DCF growth rate (id. at 10). The Attorney General asserts that because dividends are paid out of earnings, the growth in earnings could be a proxy, but with wide swings in earnings in the short-run and the possibility for changes in the payout ratio, earnings will not always be a good proxy either (id.). Finally, because dividends and earnings are derived from the book investment, the growth in investment is another possible proxy for the DCF growth rate (id. at 10-11). These proxies include

historical and forecasted measures of dividends, earnings, and book value per share growth rates as well as the growth rates from retained earning (the Attorney General also uses the term sustainable growth to mean growth from retained earnings) (id. at 9-13).

Mr. Newhard asserts that the growth from retained earnings is the best single proxy of the growth rate for the constant growth rate DCF (id. at 11-13). Stating that the growth from retained earnings does not have the same problems as the other proxies for the DCF growth rate, when used as the single proxy in the constant growth rate DCF, the Attorney General uses a 5.10 percent growth rate (id. at 13). This is the average of the five-year historical and forecasted rate of growth from retained earnings of 4.80 percent and 5.40 percent, respectively, for the Gas Group (id. at 13-14, Sch. 3).

Mr. Newhard then added to that amount the expected growth from stock issuances when the price of the stock is different from one (id. at 12-13). Using Value Line projections, he estimated this amount to be a negative 0.14 percent for the Gas Group (id. at 13-14, Sch. 4). Adding the growth from stock issuances of -0.14 percent to the growth from retained earnings of 5.10 percent, Mr. Newhard found that 4.96 percent was a reasonable estimate of the DCF growth rate (id.).

Summing the growth rate and the current dividend yield, the Attorney General asserts a ROE of 8.66 percent ($k = D/P \times (1 + 0.5 \times g) + g$ (Exh. AG-8, at 14).

The Attorney General states that Mr. Newhard's two-step DCF analysis allows for investors' growth rate expectations that might be different during certain periods, where, for instance, their short-run expectations might be different from the long-term expectations for the investment in question (Exh. AG-8, at 14-16, App. B). Mr. Newhard contends that the

two-step DCF analysis allows for investors' growth rate expectations that might be different during certain periods such as the near-term and long-run growth rates (Exh. AG-8, at 14). Mr. Newhard assumed for the Gas Group that, for the first five years, investors expect dividends per share to grow at a rate equal to an average of available five-year earnings forecasts (id. at 15). Mr. Newhard uses the latest average five-year forecast earnings per share growth rate estimates of 5.01 percent from investment analysts' surveys for this first step of the two step DCF method (id.). Accordingly, Mr. Newhard used 5.57 percent for the long-run growth rate estimate based on Blue Chip Financial forecasts survey as represented by the forecast in nominal GDP for the U.S. economy (id.). Combining the current price with investors' short-term and long-term estimates, the two-step DCF analysis yielded a 9.21 percent cost of equity estimate (id. at 16).

4. Positions of the Parties

a. Attorney General

i. Gas Group

The Attorney General states that Mr. Newhard also performed his analyses for NiSource, with the constant growth rate DCF results resulting in an ROE of 7.77 percent and the two-step DCF results of 9.49 percent (Attorney General Brief at 105). Mr. Newhard found that this range of costs of equity supported the results from the Gas Group (id.). However, the Attorney General states that the range of 8.66 percent to 9.21 percent for the Gas Group cannot be used without recognizing the differences in investment risk and expected returns between Bay State's regulated gas distribution business and those of the companies in the Gas Group (id.).

Mr. Newhard recommended that the cost of equity be set for cost of service purposes at 8.66 percent, at the lower end of the range of estimates, primarily because the Company is less risky than the Gas Group (id., citing Exh. AG-8, at 16-18). The Attorney General states that the estimates from Mr. Newhard's DCF analyses, like any analysis of this group (including Mr. Moul's results), will, therefore, tend to overstate the cost of equity for Bay State (Attorney General Brief at 106).

The Attorney General states that the base rate adjustments proposed by Bay State will also reduce the Company's cost of capital (id., citing Exh. AG-8, at 17-18). The Attorney General contends that with the addition of the new rate recovery mechanisms, the Company will go from collecting approximately 60 percent of its costs dollar for dollar to almost 85 percent of its costs dollar for dollar, with the remaining costs recovered as base rate elements (Exh. AG-8, at 17). Moreover, the Attorney General asserts that the Company will receive annual increases under its performance-based regulation plan based on the rate of inflation (Attorney General Brief at 106, citing Exh. AG-8, at 17-18).

The Attorney General asserts that given the lower risk of the gas distribution service for which the Department is setting rates in this case, 8.66 percent, the lower end of the range of cost of equity estimates derived by Mr. Newhard, is the appropriate rate to use to determine Bay State's overall cost of capital (Attorney General Brief at 106, citing Exh. AG-8, at 18).

ii. Discounted Cash Flow Analysis

The Attorney General finds fault with the Company's DCF analysis, specifically with respect to the growth rate used by Mr. Moul (Attorney General Brief at 108). The Attorney General alleges Mr. Moul proposed a DCF growth rate estimate without any basis, choosing

the highest available estimates and ignoring historical data to determine his averages, and states that the upward bias in Mr. Moul's DCF growth rate estimate is obvious (id.). The Attorney General states that the Company's growth rate estimate of 5.75 percent is based on short-term earnings per share forecasts and are over-inflated (id. at 109). The Attorney General asserts that the Department should reject Mr. Moul's proposed DCF analysis and instead rely on Mr. Newhard's more complete and better supported DCF analyses (id.).

The Attorney General states that Mr. Newhard's DCF analyses are more reliable and accurate than Mr. Moul's approaches. The Attorney General asserts that Mr. Moul has proposed a DCF growth rate estimate without any basis, choosing the highest available estimates and ignoring historical data to determine his averages. The Attorney General notes that averaging together historical dividend growth values, a representative growth rate would be 4.36 percent [(2.20 + 2.10 + 2.30 + 5.50 + 5.20 + 4.98 +5.1+ 4.0 + 7.9) / 9] (id.). The Attorney General further states that the growth rate estimate chosen by Mr. Moul for the Gas Group of 5.75 percent is 355 basis points above the historical dividend growth rate and 345 basis points above the projected dividend growth rate (id. at 108-109).

For these reasons, the Attorney General argues that the Department should reject Mr. Moul's proposed DCF analysis and instead rely on Mr. Newhard's more complete and better supported DCF analyses.

iii. Capital Asset Pricing Model

The Attorney General asserts that the Department has found that the assumptions underlying the CAPM are too "heroic" to make its application to a utility stock useful (Attorney General Brief at 111, citing D.T.E. 03-40, at 360; D.P.U. 96-50 (Phase I) at 125;

D.P.U. 92-210, at 148-150; Massachusetts Electric Company, D.P.U. 92-78, at 113 (1992); 88-67 (Phase I) at 184; D.P.U. 956, at 54-55). The Attorney General continues to note that in D.P.U. 956, the Department found the following assumptions too unrealistic:

(1) investors can borrow and lend an unlimited amount of money at a risk-free rate;

(2) investors evaluate equity/security portfolios according to the means and standard deviations of portfolio returns;

(3) there are no income taxes; and

(4) investors are "single period expected utility of terminal wealth maximizers" -- that is a 100 percent liquidating dividend is paid at the end of the period

(Attorney General Brief at 111-112).

The Attorney General finds these assumptions to be unrealistic, and states that Mr. Moul's analysis never attempts to address any of the fundamental problems with these assumptions (id. At 112). The Department should reject the use of the CAPM analysis as a method for determining the cost of equity for utilities, as it has done in the past (id.).

iv. Risk Premium Analysis

The Attorney General asserts that although the Company states that its RP analysis is separate and distinct from the CAPM analysis, it is essentially the same analysis (id. at 113). The Attorney General also notes that the Department has reviewed and rejected RP analyses like Mr. Moul's many times before, and as there is no new analysis or argument provided demonstrating the applicability of this approach, the Department should reject the Company's use of the RP analysis (id.).

v. Comparable Earnings Approach

The Attorney General states that the Department should reject the Company's use of a CE analysis because the Department has rejected the use of this approach on numerous occasions (id. at 112, citing D.T.E. 03-40, at 360-361; D.P.U. 96-50 (Phase 1), at 131-132; D.P.U. 92-250, at 160-161; D.P.U. 92-111, at 280-281; D.P.U. 92-210, at 155; D.P.U. 905, at 48-49).

The Attorney General continues to note that the Department has previously rejected Mr. Moul's use of the CE approach as unreliable, because the earned return on common equity did not necessarily equal the companies' cost of capital (Attorney General Brief at 112, citing D.P.U. 905, at 48-49). Finally, the Attorney General notes that Mr. Moul has provided no reason in this case for the Department to change its well-founded precedent, and that, therefore, the Department should reject Mr. Moul's CE analysis, since its results are unreliable (Attorney General Brief at 113).

vi. SIR Proposal and Management Issues

The Attorney General contends that Bay State has identified its proposed SIR cost recovery mechanism as a means to send the appropriate signal about the Company's risk to the investment community (Attorney General Reply Brief at 46-47). The Attorney General alleges, however, that the SIR adjustment mechanism will increase the Department's administrative oversight requirements and costs related to the gas, electric, and water utilities under its jurisdiction that will seek similar pass-through clauses for all of their capital additions (id. at 47). The Attorney General also states that the SIR mechanism will allow more than 83 percent of a utility's costs to be passed through dollar for dollar with the remaining costs recovered with annual inflation increases through the price cap formula, as well as remove

incentives for utilities to reduce costs and become more efficient (id.). Additionally, the Attorney General states that the SIR mechanism will increase rates (id.). The Attorney General also finds that Mr. Newhard's analysis provides sufficient inclusion of the expectation of changing capital cost rates (id. at 48). The Attorney General asserts that the Department should reject the Company's proposed SIR mechanism because of these problems, and because the annual price cap increases will more than compensate the Company for its capital additions (id. at 47).

The Attorney General supports the recommendations of Local 273 in setting the Company's ROE at the low end of reasonableness for subpar performance, and for an independent audit to investigate the performance of management (id. at 50). The Attorney General raises the issues of the Company's inability to ensure compliance with its own O&M manual, the Company's negligence in following Department precedent concerning appropriate back-fill materials on repaired mains, the Company's lack of updates in its system maps, and inadequate regulatory support during the discovery phase of this proceeding (id.).

b. Local 273

Local 273 states that the Department should set Bay State's return at the lowest end of a reasonable range of rates (UWUA Brief at 17). While Local 273 supports the quantitative analysis performed by the Attorney General, Local 273 reasons that the Attorney General's proposed ROE was predicated on the assumption of a prudent and well-managed company, and did not make adjustments for management issues (id.). Taking the Attorney General's proposed ROE of 8.66 percent, Local 273 recommends a 50 basis point reduction for subpar management performance, resulting in a ROE of 8.16 percent (UWUA Brief at 46-47; UWUA

Reply Brief at 11). In support of its proposed adjustment, Local 273 notes that Department precedent supports the use of judgment in setting a company's ROE, and that the Department has the discretion to choose from a reasonable range of rates (UWUA Brief at 17, citing Boston Edison Co. v. Department of Public Utilities, 375 Mass. 1, 11-12 (1978)).

Citing claims about the Company's sub par management practices,[156] Local 273 states that the Department must send the strongest signal poss1ible that Bay State's customers suffer as a result of actions taken by NiSource (UWUA Brief at 18-19). Local 273 recommends that the Department set the ROE at the low end of the range of reasonable returns as a result of the Company's poor performance, including inadequate staffing, inappropriate outsourcing, poor call center performance, and failure to meet its public service obligations to low-income customers (id. at 20-45).

c. Company

i. Gas Group

Bay State argues that, on balance, its chosen Gas Group provides a reasonable basis for a conservative measure of its required ROE (Company Brief at 195, citing Exh. BSG/PRM-1, at 20). The Company contends that it evaluated various aspects of Bay State and the companies that comprise the Gas Group to reach this conclusion (Exh. BSG/PRM-1, at 16-20). The Company states that 73 percent of the Gas Group's revenues, 89 percent of its income, and 88 percent of its identifiable assets are from the gas utility business (id. at 15). According to Bay State, the Company is weaker than the Gas Group in several important aspects,

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[156] See Section X, below.

including a lower credit rating, higher operating ratio, and lower interest coverage ratio (Company Brief at 198).

In addition to these financial risk factors, the Company states that there are a number of other risk factors affecting both Bay State and the natural gas distribution business that the Department should take into consideration in determining the appropriate ROE (id.). The Company asserts that high gas commodity prices and the volatility of those prices, the unbundling of rates and the implementation of customer choice, the availability of customer-owned transportation gas, the uncertainty of delivery of volumes to dual fuel customers on the Company's system, the threat of bypass, and competition from alternative energy sources all have increased the Company's risk (id., citing Exh. BSG/PRM-1, at 6-8; Tr. 7, at 1154). The Company also states that it will face a significant amount of risk associated with its large construction program in the form of its SIR (Company Brief at 199). Although the Company states its proposed SIR mechanism will reduce some of the attendant risks associated with its construction program, these risks are not completely eliminated (id. at 199-200).

ii. Discounted Cash Flow Analysis

Bay State states that its DCF analysis resulted in an ROE of 10.21 percent, which the Company considers to be an atypical result because it is the only model that provided a cost of equity less than 11.0 percent (Company Brief at 197, citing Exh. BSG/PRM-1, at 5; Tr. 7, at 1180). The Company asserts that this is due to the unfavorable investor sentiment for gas companies, as evidenced by the Value Line Timeliness Rank for the Gas Group of "4" (Company Brief at 197, citing Exh. BSG/PRM-1, at 5). Bay State notes that this places gas

companies in a below average category and indicates that they are relatively unattractive investments (Company Brief at 197). The Company asserts that natural gas distribution companies are currently ranked 97th out of 98 industries for probable performance over the next twelve months, and as a result, Mr. Moul recommends less reliance on the DCF method in this case (id., citing Exh. BSG/PRM-1, at 5). In addition, Bay State considers an 11.5 percent ROE to be reasonable in light of the Company's proposed PBR term of five years and the existence of the risk that unforeseen events will occur during the term of the PBR plan (Company Brief at 197, citing Exh. BSG/PRM-1, at 6).

The Company states that Mr. Moul's analysis produced an adjusted dividend yield of 3.82 percent based on the six-month average dividend yield of the Gas Group (Company Brief at 201, citing Exh. BSG/PRM-1, at 15-16). The Company also states that Mr. Moul uses projections of earnings per share growth such as those published by IBIS/First Call, Zacks, Reuters/Market Guide and Value Line to determine the DCF growth rate over a five-year period, as well as forecasts of growth in overall corporate profits for five-year and ten-year periods to determine a growth rate of 5.75 percent (Company Brief at 201, citing Exh. BSG/PRM-1, at 31-34).

Finally, the Company notes that Mr. Moul adds a leverage adjustment to the dividend yield and growth rate figures to account for the divergence of market capitalization from book capitalization, which is common in the utility industry today and is the case for the companies in the Gas Group (Company Brief at 202, citing Exhs. BSG/PRM-1, at 35; BSG/PRM-1, App. E at 13). Bay State asserts that a financial risk difference is created when the results of a market-derived cost of equity are applied to the common equity ratio measured at book value,

which is the measure used by the Department in calculating the weighted average cost of capital (Company Brief at 202).

The Company states that the capitalization of a utility measured at its market value contains relatively less debt and more equity than capitalization measured at book value, and, therefore, the capital structure ratios measured at a utility's book value show more financial leverage, and higher risk than the capitalization measured at market values (Company Brief at 202, citing Exh. BSG/PRM-1, at 34-35). The Company states that it is, therefore, necessary to adjust the market-determined cost of equity upward to reflect the higher financial risk related to the book value capitalization used for rate setting purposes (Company Brief at 202, citing Exh. BSG/PRM-1). Accordingly, Bay State proposes a leverage adjustment of 0.64 percent (Company Brief at 202, citing Exh. BSG/PRM-1, at 36).

The Company states that Mr. Moul has presented this modification to the Department in other rate case proceedings, and that, in those instances, the Department declined to recognize this adjustment (Exh. BSG/PRM-1, at 36). Bay State emphasizes that the adjustment addresses strictly the issue of financial risk, and is not dependent upon a price-to-book ratio, as suggested by the Department in the past (id.). The Company asserts that there is no input variable for any price-to-book ratio in Mr. Moul's formulas, nor does he attempt to ensure a price-to-book ratio of 1:1 (id. at 37). Rather, the Company considers the adjustment to simply provide recognition to the financial risk difference between market capitalization and book value capitalization, with no target price-to-book ratio (id.). Finally, Bay State contends that there is no need to address a company's location, load factors, or customer makeup, as they have no bearing on the financial risk of a company (id.). According to the Company, these are

factors relevant to business risk, and, therefore, have no bearing on a financial adjustment (id.).

The Company asserts that the Department should reject the ROE analyses performed by the Attorney General. The Company states that Mr. Newhard's analysis of NiSource cannot be relied on because the Department has consistently rejected the use of a parent company in a DCF analysis as a proxy to develop the cost of equity for a subsidiary that has no publicly traded stock (Company Brief at 206, citing D.P.U. 95-40, at 96). Bay State asserts that the rate of return proposed by Mr. Newhard is inadequate to provide the Company with its cost of capital for the five-year period of the Company's proposed performance -based regulation plan (Company Brief at 206, citing Exh. BSG/Rebuttal-3, at 2). Additionally, the Company asserts that the ROE recommended by the Attorney General will not accommodate any upward movement in capital costs, and additionally notes that his recommended ROE of 8.66 percent does not come close to the returns actually expected by investors in energy utilities (Company Brief at 206, citing Exh. BSG/Rebuttal-3, at 2).

The Company also states that Mr. Newhard's analyses are not reliable, as no single method is sufficiently reliable to establish the cost of equity without further verification (Company Brief at 209). Bay State additionally contends that the two-step DCF model used by Mr. Newhard has not found wide acceptance in public utility ratesetting, and those results should also be rejected by the Department (id., citing Exh. BSG/Rebuttal-3).

iii. Risk Premium Analysis

The Company maintains that it used a 7.00 percent yield as a reasonable estimate of the prospective yield on long-term A-rated public utility bonds for the period proposed in the Company's PBR Plan (Company Brief at 203). Bay State argues that this estimate recognizes that the prospect of maintaining the current low long-term interest rates, or even lower long-term interest rates, is outweighed by the prospect of higher future interest rates, particularly as a result of the policy of the Federal Open Market Committee, which is now in transition and is in the process of raising the short-term Federal Funds rate (id., citing Exh. BSG/PRM-1, at 38-40). To determine equity risk premium, the Company states that it analyzed the equity returns for the S&P Public Utilities compared with the returns on utility bonds, and determined a reasonable risk premium of 4.95 percent (Company Brief at 203-204, citing Exh. BSG/PRM-1, at 41-42). Therefore, the Company maintains that the overall cost of equity based on the risk premium analysis is 11.75 percent (Company Brief at 203).

iv. Capital Asset Pricing Model

The Company states that the CAPM is a variation of the risk premium analysis that employs the yield on a risk-free interest-bearing obligation plus a premium as compensation for risk (id. at 204, citing Exh. BSG/PRM-1, at 95). The Company states that its CAPM analysis produced a risk-free rate of return of 6.00 percent, a leverage adjusted Beta of 0.85, and a 6.00 percent market premium, producing an overall cost of equity of 12.01 percent (Company Brief at 204, citing Exh. BSG/PRM-1, at 48).

v. Comparable Earnings Approach

The Company states that its comparable earnings analysis relies on both historical returns and forecasted returns for the non-utility companies (Company Brief at 205, citing Exhs. BSG/PRM-1, at 51; BSG/PRM-2, Sch. PRM-13).[157] The Company asserts that the average of the historical and forecast median rates of return for the comparable earnings analysis was 13.70 percent (Company Brief at 205, citing Exh. BSG/PRM-1, at 52).

Using both historical realized returns and forecast returns for non-utility companies, Mr. Moul considered his comparison group over a period of ten years - five historical and five forecast - and found an historical rate of return on book common equity of 13.9% and forecast rates of return as 13.5% (Exh. BSG/PRM-1, at 52). Averaging the two, Mr. Moul reached a rate of return of 13.7% based on his comparable earnings approach (id.).

vi. Management Issues

Finally, the Company maintains that Local 273's proposed adjustment for alleged management failures, supported by the Attorney General, is inappropriate and unwarranted, because past problems have been resolved, and the Company has met all of its service quality standards since 2002 (Company Brief at 214). Consequently, the Company considers that Local 273's proposed ROE penalty is inappropriate and unwarranted for a number of reasons (id.). The Company asserts that the events cited by Local 273 supporting a penalty occurred several years ago, and, therefore, there is no basis to penalize current management for events so far in the past (id.).

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[157] The companies used in the comparable earnings analysis include representatives of such industries as shipping, food processing, newspapers, advertising, restaurants, medical supplies, and machinery (Exh. BSG/PRM-2, Sch. 13, at 1).

Bay State asserts that it now meets all of its service quality standards in Massachusetts, and has done so since 2002 (id.). Therefore, the Company finds that a return penalty attributed to events before 2002 would serve no purpose (id.). In addition, the Company argues that because the Department's service quality standards already include a penalty mechanism for poor performance, an ROE penalty would amount to a duplication and double-counting of the Department's service quality penalties (id.). The Company also states that because a return penalty would stay in effect for the five years of Bay State's proposed PBR plan, there would be no opportunity or motivation for the Company to improve performance and eliminate the penalty during the term of the PBR (id. at 214-215).

In response to the Attorney General's allegations of "management failures" relating to the Company's backfilling practice when repairing mains, Bay State argues that it has performed appropriately, followed its O&M manual, and has not been notified by the Department of any failure to follow the Department's standards for excavations (Company Reply Brief at 52, citing Tr. 22, at 3717). Regarding other managerial shortcomings described by the Attorney General, the Company states that there is no basis for these allegations, and, therefore, the Attorney General's recommendation that the ROE be set at the low end of reasonableness should be rejected (Company Reply Brief at 53).

5. Analysis and Findings

a. Gas Group

In our evaluation of the Gas Group used by Bay State, we recognize it is neither necessary nor possible to find a group that matches the Company in every detail.[158] D.T.E. 02-24/25, at 225; D.T.E. 99-118, at 80; D.T.E. 98-51, at 108; D.T.E. 96-50 (Phase I) at 115. Rather, we may rely on an analysis that employs valid criteria to determine which utilities will be in a comparison group, and that provides sufficient financial and operating data to discern the investment risk of the subject company versus the comparison group. D.T.E. 02-24/25, at 225; D.T.E. 99-118, at 80; D.T.E. 98-51, at 108; D.P.U. 87-59, at 68. Bay State's Gas Group includes companies that have operations beyond the scope of gas distribution, which could make these companies more risky and, in turn, potentially more profitable. However, the Company has shown that, as concerns historical earnings volatility, these companies are on par with Bay State (Exh. BSG/PRM-2, Schs. 2, 3). Other factors, such as the Gas Group's company size, market ratios, common equity, operating ratios, coverage ratios, quality of earnings, and internally generated funds, betas, provide an acceptable basis for evaluating the relative risks of the Company. While the Company's higher coverage ratio versus that of the Gas Group indicates that Bay State has a lower risk, other factors, such as the Company's smaller size and greater volatility of earnings in relation to the Gas Group, indicate that Bay State may have equal or greater risk (id.). On balance, after review of the Company's financial and operating statistics in relation to the Gas Group, the

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[158] It is important that the reader note that the Gas Group used as a proxy group for the Company's DCF, RP, and CAPM models not be confused with the comparison group used in the CE analysis.

Department finds that Bay State is reasonably comparable to the Gas Group employed in this proceeding.

b. Discounted Cash Flow Analysis

In the past, the Department has addressed various forms of DCF analyses as a basis for determining an appropriate return on equity. See D.T.E. 02-24/25, at 226-228; D.P.U. 96-50 (Phase I) at 119-120; D.P.U. 95-40, at 96-97; D.P.U. 93-60, at 250-251. As indicated above, the Company-proposed DCF model postulates that the value of an asset is equal to the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Because the dividend yield and growth rate components of this risk-adjusted rate of return are variables that reflect investors' expectations of future performance of stock investment, there will always be potential problems and limitations in estimating the appropriate values of these two variables. D.T.E. 96-50 (Phase I) at 120.

Regarding the yield component of the DCF, the Department previously has rejected those adjustments that tend to overstate the dividend yield component and, consequently, the DCF-based cost of equity. More specifically, the Department has rejected financing and market adjustments and those adjustments which could double-count the effect of the yield factor. D.P.U. 95-40, at 97; D.P.U. 93-60, at 250; D.P.U. 90-121, at 178-180. In addition, the Department has rejected the inclusion of financing and market adjustments because investors incorporate a premium into their expected return to reflect market risks and financing costs. D.P.U. 95-40, at 97; D.P.U. 90-121, at 178-180.

In this case, Bay State added a 0.64 percent leverage adjustment (Exh. BSG/PRM-1, at 36). Although the Company has provided more explanation as to the reasons for this

proposed adjustment, the underlying factors behind the proposed leverage adjustment emphasize the difference between book and market capitalization, and thus the adjustment contains the same defects as the Department has previously identified, including insufficient consideration of the multiplicity of factors that affect investor decisions. D.T.E. 01-56, at 105. Also, despite Bay State's claims to the contrary, the Company's leverage adjustment is similar to the now little used price-to-book ratio method of determining a utility's cost of capital, which the Department has frequently rejected because of its failure to recognize important variables and its excessive reliance on investor perceptions of the relationship between market and book prices. D.P.U. 906, at 100-101; Eastern Edison Company, D.P.U. 837, at 49 (1982).

The Department has found that a balanced examination of growth rates must be made. D.T.E. 99-118, at 83; D.T.E. 98-51, at 120. These factors, such as growth in earnings-per-share and dividends-per-share, should be taken into consideration when determining an appropriate growth rate. D.P.U. 96-50 (Phase I) at 120; D.P.U. 93-60, at 251; D.P.U. 92-250, at 147; D.P.U. 88-135/151, at 125. The Attorney General has relied on a variety of historical and forecast growth rates for dividends, earnings, and book value as a means to estimate investor-expected growth. Notwithstanding the limitations that must be considered in the use of forecast growth rates, the Department has recognized the value of forecast data as a conceptually appropriate measure of growth. D.P.U. 94-50, at 460; D.P.U. 88-250, at 97. Accordingly, the Department will consider a variety of growth rates in our evaluation of the Company's required ROE.

Based on the above considerations, the Department finds that the Company's contention that its DCF analysis understates the required ROE for Bay State is not accurate. Therefore, the Department will give greater weight to the Company's DCF analysis than requested by Bay State.

c. Risk Premium Analysis

The Department has repeatedly found that a risk premium analysis overstates the amount of company-specific risk and, therefore, overstates the cost of equity. D.T.E. 02-24/25, at 228; D.T.E. 98-51, at 126; D.P.U. 90-121, at 171; D.P.U. 88-135/151, at 125-125; D.P.U. 88-67, Phase I at 182-184. The Department has acknowledged the value of risk premium analysis as a supplemental approach to other ROE models but has accorded it, at best, limited weight in our determination of the cost of equity. D.T.E. 02-24/25, at 228; D.T.E. 99-118, at 86-87. The S&P Utility bond yield indices that Bay State relied upon include vertically-integrated companies whose operations are not confined to gas distribution services and are unrepresentative of the Company's risk and debt component. Additionally, the Department is not persuaded that the 1979 to 2001 data used to derive the risk premium represent a reliable indication of investment fundamentals. Because Bay State's risk premium analysis suffers from the same limitations previously noted by the Department, we will place limited weight on these results in determining the Company's ROE.

d. Capital Asset Pricing Model

The Department has rejected the use of the CAPM as a basis for determining a utility's cost of equity. D.P.U. 92-78, at 113; D.P.U. 88-67, Phase I at 184; D.P.U. 84-94, at 63-64. The Department has previously noted a number of limitations in the application of CAPM,

including the definition and data used to estimate the risk-free rate, and the coefficient of determination of beta. D.P.U. 93-60, at 257.

The same deficiencies in the CAPM identified in prior cases are also present here (e.g., there are no income taxes included in the calculation, a 100 percent liquidating dividend is paid at the end of the period.) In addition to these limitations, the Company's CAPM model relies on leveraged betas, which are intended to adjust the results of the analysis for market versus book valuations. As in our analysis of the leverage component of Bay State's DCF model, the Department finds that the use of leveraged betas in the Company's CAPM model overstates the required ROE for Bay State. Accordingly, we will not rely on the results of the CAPM analysis as a means of corroborating the results of Bay State's DCF and risk premium analyses.

e. Comparable Earnings Approach

The Company presented a comparable earnings analysis a method to calculate the Company's ROE. The comparison group of companies used in its comparable earnings approach consist of non-regulated, non-utility firms including representatives of such industries as shipping, food processing, newspapers, advertising, restaurants, medical supplies, and machinery (Exh. BSG/PRM-2, Sch. 13, at 1). Although the screening criteria used to select the comparison companies appear to produce a sample that is consistent with the Gas Group, the risk of companies operating in other industries differs significantly from the risk associated with gas LDCs, such as Bay State. In order to meet the comparability criteria set forth by the United States Supreme Court in Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield") and Federal Power

Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) ("Hope"), investment risk criteria must be carefully evaluated in selecting a comparable group of companies. D.P.U. 92-250, at 160-161.

While the Company's comparison group may fall within the six investment risk criteria used in the analysis, Bay State has not demonstrated the validity of its criteria. For example, the Company's financial strength indicator combines a broad range or risk criteria into a single factor (Exh. BSG/PRM-1, App. I at 2). This blending of investment criteria serves to mask the individual risk components that the Department must assess in determining comparability. See D.P.U. 87-59, at 68. Additionally, the use of beta as a criterion in selecting the comparison group of companies is not a reliable investment risk indicator, given its statistical measurement limitations (D.T.E. 01-56, at 116; D.T.E. 96-50 (Phase I) at 132). Furthermore, the Company has not demonstrated the relevance of its technical rank risk criterion, and how its measurement of price action relative to stocks reported on Value Line relates to Bay State's risk factors.

The Department has consistently found that the CE analysis is not as strong an analysis to use in deriving a company's ROE. D.T.E. 03-40, at 360-361; D.P.U. 96-50 (Phase 1), at 131-132; D.P.U. 92-250, at 160-161; D.P.U. 92-111, at 280-281; D.P.U. 92-210, at 155. Further, we are not persuaded that the Company's selection of risk criteria such as financial strength, beta, and technical rank assist in determining a reasonable ROE for Bay State. Department precedent gives little weight to the CE analysis. The Company has provided no new evidence to change our position.

f. Conclusion

The Company has presented various financial methods, such as DCF, CAPM, RP, and CE analyses, in support of its calculation of an appropriate return on equity. These methods include the use of projected growth rates, current and projected interest rates, and financial statistics for the Company and the Gas Group. However, the use of empirical analyses in this context is not an exact science. The Department looks for substantial evidence on which we may reasonably rely to base a judgment. Each level of judgment to be made contains possibility of inherent bias and other limitations. D.T.E. 01-56, at 117; Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977).

The record in this proceeding shows that there is a wide range of results produced by the Company and the Attorney General. For reasons explained above, the Department gives little weight to the Company's CAPM, RP, and CE analyses. The DCF analyses performed by the Company and the Attorney General, while troublesome in certain respects, nonetheless adequately assist the Department in finding a range of reasonable ROEs. The results of analytical models are useful, but the Department must ultimately apply its own judgment to the evidence to determine an appropriate rate of return. We must apply to the record evidence and argument considerable judgment and agency expertise to determine the appropriate use of the empirical results. Our task is not a mechanical or model-driven exercise. D.T.E. 01-56, at 118; D.P.U. 18731, at 59; see also Boston Edison Company v. Dep't of Pub. Utils., 375 Mass. 1, 15 (1978).

Based on a review of the evidence presented in this case, the arguments of the parties, and the considerations set forth above, the Department finds that an allowed rate of return on common equity of 10.0 percent is within a reasonable range of rates that will preserve Bay

State's financial integrity, will allow it to attract capital on reasonable terms, will be comparable to earnings of companies of similar risk, and is appropriate in this case. In making these findings, we have considered both qualitative and quantitative aspects of the Company's various methods for determining its proposed rate of return on equity, as well as the arguments of the parties in this proceeding.

In the Department's determination of an appropriate ROE for Bay State, we have considered the changes in the Company's financial risk brought about by the pension/PBOP reconciliation mechanism and bad debt reconciliation mechanism through the operation of the LDAC. The Department has also evaluated the Company's relative risk under the ten-year PBR plan adopted in this proceeding. The conditional leave for the Company to seek a one-time base rate adjustment associated with its steel infrastructure replacements, exogenous cost recovery provisions, earnings sharing mechanism, and fixed threshold at which the Company qualifies for exogenous cost recovery, serves to offset risk that may occur under a ten-year PBR plan.

At the time of the Company's acquisition in 1998, representations were made that Bay State would continue to have strong local management, local operations would not be affected, and significantly increased sales would result from the merger (Exh. UWUA-4, at 21, 29-30). D.T.E. 98-31, at 48. Despite these representations, there is evidence that NiSource has engaged in significant staff reductions, reduced its infrastructure investment, and curtailed its sales efforts (Exhs. UWUA 1-1(B); UWUA 1-21; UWUA 1-23; UWUA-4, at 24; Tr. 12, at 2014-2015). Moreover, NiSource has effectively taken control of staffing and other business matters from local Bay State management, and failed to respond in a timely manner

when local management urged NiSource to allow additional hirings in order to meet acceptable service standards.

We do not want, in advance of our G. L. c. 164, § 1E ("Section 1E") enquiry described in Section X below, to suggest, much less reach, fixed or even tentative conclusions about NiSource's management of its Bay State subsidiary. Yet, the very fact of opening such an enquiry signals our concern about that relationship. Note that we say NiSource's management of Bay State, for the record in the present docket, raises questions not so much about local level managers' conduct as about decisions of the parent company as these decisions may affect resources and services (in both capital and personnel) available to Bay State's customers - decisions that, on their face at least, raise further questions about consistency with the representations made during the D.T.E. 98-31 acquisition proceeding.

This is serious business, and we advise NiSource so to regard it. Our Section 1E enquiry will rely on our general supervisory authority in G.L. c. 164 - particularly §§ 76, 76A, and 85. Merely citing these last two sections of the statute should alert the Company and its parent that Merrillville is at least as much, and maybe even more the subject of our investigation as Westborough, where local managers strive to maintain service in the face of the holding company's resource allocation decisions.

VII. COST ALLOCATION AND RATE DESIGN

A. Rate Structure Goals

Rate structure is the level and pattern of prices charged to customers for their use of utility service. Rate structure for each rate class is a function of the cost of serving that rate

class. Rate structure also considers the design of the rates so that the cost to serve a rate class is recovered in the rates charged that class.

Utility rate structures must be efficient, simple, and ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.T.E. 03-40, at 365; D.T.E. 01-56, at 134; D.T.E. 01-50, at 28; D.P.U. 96-50 (Phase I) at 133. Efficiency means that the rate structure should allow a company to recover the cost of providing the service and should provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest-cost means for society as a whole. Thus, efficiency in rate structure means setting cost-based rates that recover the cost to society of the consumption of resources used to produce the utility service. D.T.E. 03-40, at 365; D.T.E. 01-56, at 135; D.T.E. 02-24/25, at 252-53.

A rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. Fairness means that no class of consumers should pay more than the costs of serving that class. Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. D.T.E. 03-40, at 365; D.T.E. 01-56, at 135; D.T.E. 02-24/25, at 252-253.

There are two steps in determining rate structure: cost allocation and rate design. The cost allocation step assigns a portion of the company's total costs to each rate class in a cost of service study ("COSS"). The COSS represents the cost of serving each class at equalized rates

of return given the company's level of total costs. D.T.E. 03-40, at 367; D.T.E. 01-56, at 135; D.T.E. 01-50, at 29; D.P.U. 96-50 (Phase I) at 133.

There are four steps to develop a COSS. The first step is to classify costs by category, according to the service function they provide -- either (1) production and storage or (2) transmission and distribution. The second step is to classify expenses in each functional category according to the factors underlying their causation (i.e., demand-, energy-, or customer-related). The third step is to identify the most appropriate allocator for costs in each classification within each function. The fourth step is to allocate all of a company's costs to each rate class based upon the cost groupings and allocators chosen, and to sum these allocations in order to determine the total costs of serving each rate class. D.T.E. 03-40, at 367; D.T.E. 01-56, at 136; D.T.E. 98-51, at 132; D.P.U. 96-50 (Phase I) at 133-134.

The results of the COSS are compared to the revenues collected in the test year. If these amounts are close, then the revenue increase or decrease may be allocated among the rate classes so as to equalize the rates of return and ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test year revenues are great, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize them in a single step. See D.T.E. 01-56, at 135; D.T.E. 01-50, at 29.

As the previous discussion indicates, the Department does not determine rates based solely on costs, but also explicitly considers the effect of its rate structure decisions on customers' bills. For instance, the pace at which fully cost-based rates are implemented depends in part on the effect of the changes on customers. The Department has ordered the

establishment of special subsidized rate classes for certain low-income customers. In moving toward our goal of efficiency, the Department also considers the effect of such rates on low-income customers. D.T.E. 03-40, at 368; D.T.E. 01-56, at 136; D.T.E. 01-50, at 29-30.

In order to reach fair decisions that encourage efficient utility and consumer actions, the Department's rate structure goals must balance the often divergent interests of various customer classes and prevent any class from subsidizing another unless a clear record exists to support such subsidies – or they are required by statute, e.g., G.L. c. 164, § 1F(4)(I). The Department reaffirms its rate structure goals that result in rates that are fair and cost-based and enable customers to adjust to changes. D.T.E. 03-40, at 368; D.T.E. 01-56, at 136-137; D.T.E. 01-50, at 30.

The second step in determining the rate structure is rate design. The level of the revenues to be generated by a given rate structure is governed by the cost allocated to each rate class in the cost allocation process. The pattern of prices in the rate structure, which produces the given level of revenues, is a function of the rate design. The rate design for a given rate class is constrained by the requirement that it should produce sufficient revenues to cover the cost of serving the given rate class and, to the extent possible, meet the Department's rate structure goals discussed above. D.T.E. 03-40, at 368; D.T.E. 01-56, at 136-137; D.T.E. 01-50, at 30.

B. Cost Allocation

The Company performed an allocated COSS as a basis to assign or allocate costs to customer rate classes, and filed three separate COSS results (Exhs. BSG/JLH-2, Sch. JLH 2-2; BSG/JLH-2, Sch. JLH 2-3; BSG/JLH-2, Sch. JLH 2-4). The first study presents the allocated

COSS for the total cost of service for the delivery function only (excluding supply-related costs to be recovered through the Cost of Gas Adjustment Clause or the delivery-related costs to be recovered through the Local Distribution Adjustment Clause) (Exhs. BSG/JLH-2, at 2; BSG/JLH-2, Sch. JLH 2-2). The second study presents the allocated COSS performed to determine the supply-related costs (Exhs. BSG/JLH-2, at 2; BSG/JLH-2, Sch. JLH 2-3). The third study sets forth a COSS that presents total costs for the supply and delivery functions rather than by rate class (Exhs. BSG/JLH-2, at 2; BSG/JLH-2, Sch. JLH 2-4).

The Company argues that, through this supporting information, it has demonstrated that its COSS properly allocates the Company's costs and revenues to customer classes, in a manner consistent with Department precedent (Bay State Brief at 226). No other party commented on the Company's proposed allocated COSS.

The Department has evaluated the Company's proposed COSS and finds that it is consistent with Department precedent for cost allocation. D.T.E. 03-40, at 369; D.T.E. 01-56, at 138; D.P.U. 96-50 (Phase I) at 136. The Department directs the Company, in its compliance filing, to re-run its COSS to allocate costs and expenses consistent with this Order.

C. Gas Cost Allocation and CGAC

1. Gas Cost Allocation

a. Company's Proposals

The Company proposes to: (1) replace the existing Market-Based Allocator ("MBA") with a Simplified Market-Based Allocator ("SMBA") to allocate the Company's gas production costs in its accounting COSS (Exh. BSG/JLH-1, at 1-2); and (2) use the SMBA to calculate

seasonal gas costs by load factor in the Company's Cost of Gas Adjustment Clause ("CGAC") (Exh. BSG/JAF-3-1, at 12-13).

The SMBA method identifies two portions of a utility's load-duration curve and separately assigns costs to each portion of the curve (Exh. BSG/JLH-1, at 9). The "base-use"[159] or high load factor block is computed as the average daily, normal-year firm sendout over the months of July and August (id. at 10). Under the SMBA, the Company identifies the capacity and commodity costs for both supply and transportation contracts used to supply the high load factor demand and assigns these costs, on average, to the high load factor customer classes (id. at 9-10). To allocate costs to the load remaining after serving the high load factor block, the Company proposes to replace the detailed, design-year, daily allocation of the MBA with a monthly allocation using the results of the Company's daily dispatching model (id. at 11). Specifically, the remaining load capacity is allocated to rate classes on the basis of their respective design-day load less that portion of their load served by base-use supplies (id.). Capacity costs are assigned to months using a Proportional Responsibility ("PR") allocator based on the system's remaining load in a normal year (id.). Monthly costs are then allocated to customer classes in proportion to their monthly usage, after deducting load served by the high load factor block (id.).

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[159] The SMBA method defines base use as the level of system firm customer load that remains constant throughout the year (Exh. BSG/JLH-1, at 10). The "remaining load" after serving the high load factor block consists of firm loads in the winter period, interruptible load, storage refill, and a minor amount of firm load served on cooler summer days (id. at 11).

The Company contends that its proposed SMBA method is administratively simpler than the MBA method currently in place because it reduces the number and complexity of the required calculations (Tr. 3, at 657). The SMBA uses a single, normal-weather monthly dispatch for both commodity and capacity (Exh. BSG/JLH-1, at 8, 11). By comparison, the MBA currently in use requires an individual dispatch for every supply source (Tr. 3, at 653). The Company further claims that the proposed SMBA is consistent with the method approved by the Department in D.T.E. 02-24/25 and D.T.E. 01-56 (id. at 657, 659). According to the Company, adoption of the SMBA will result in approximately a 0.3 percent decrease in costs allocated to the low load factor rate classes in the winter period, and a 4.5 percent increase in costs allocated to the high load factor classes in winter; the impacts in the summer would be smaller (Exh. BSG/JLH-1, at 19-20).

The Company also argues that the current MBA method is inconsistent with the gas capacity assignment method prescribed in D.T.E. 98-32, in that transportation capacity contracts are assigned to transportation customers on the basis of a design-day allocator, while under the current MBA method, capacity costs are allocated using a Proportional Responsibility design-year daily allocator (id. at 7). Since the proposed SMBA is based on a design-day allocator, the capacity-related costs assigned to migrating sales customers are the same costs charged to them when they were sales customers (id. at 9).

Currently, the Company calculates its seasonal GAF separately for each of its rate classes based on the CGAC tariff approved by the Department in Bay State's last rate case. Under its current proposal, the Company would replace the existing seasonal GAFs with two seasonal GAFs, one applicable to low load factor rate classes (i.e., R-3, R-4, G-41, G-42,

G-43), and the other applicable to high load factor rate classes (i.e., R-1, R-2, G-51, G-52, and G-53) (Exh. BSG/JLH-1, at 20; RR-DTE-174, at 4).

The Company stated that the variations in gas costs among individual high load and low load factor customer classes are very small (id., at 20-21). Bay State argues that two prices are adequate to provide customers with necessary price signals and will avoid the complexity of maintaining separate CGAC prices for each rate schedule (id.). The Company stated that the proposed CGAC revision is consistent with the CGAC approved by the Department for Berkshire and Fitchburg (id., at 20).

b. Positions of the Parties

No party commented on the Company's SMBA proposal or the load factor-based GAF proposal.

c. Analysis and Findings

Regarding the Company's proposal to adopt the SMBA method to allocate production costs, the Department notes that the SMBA is conceptually identical to the MBA methodologies approved by the Department in D.T.E. 02-24/25, at 249-252 and D.T.E. 01-56, at 128. Further, Bay State's proposed modification is consistent with our mandatory capacity assignment method for customers migrating to transportation service, which was approved by the Department in D.T.E. 98-32-B. We note that none of the parties opposed the Company's proposal. Based on a review of the record in this case, the Department finds the Company's proposal to allocate production costs using the SMBA is reasonable and consistent with Department precedent. Accordingly, the Department approves the Company's proposal.

Regarding the use of seasonal GAFs by load factor, the Department has accepted this linkage before. See D.T.E. 01-56, at 130; D.T.E. 98-51, at 154. Specifically, in approving seasonal load factor-based GAFs in D.T.E. 98-51, the Department noted that such an approach represents costs more accurately than a single seasonal GAF that is applicable to all rate classes, and therefore avoids inter-class subsidy. Id. at 153. In addition, the Department noted that a load-factor-based GAF is likely to lead to more effective competition by reducing "cherry picking" and may encourage customers to improve their load factors through improvements in efficiency or through load-shifting (id.).[160] We note that currently Bay State does not have a single seasonal GAF applicable to all rate classes, as was the case in D.T.E. 98-51, but rather Bay State applies a separate GAF for each rate class. A load-factor-based GAF will simplify the CGAC filings and is consistent with what the Department has approved for Berkshire and Fitchburg. Accordingly, the Department approves Bay State's proposed load factor based GAF.

2. CGAC Tariff Changes

a. Description of Tariff Changes

The Company has proposed two primary changes to its CGAC and LDAC tariffs (Exh. BSG/JAF-3, at 12). The first of these modifications is to implement the SMBA methodology to the gas-cost allocation in the CGAC (id.). The second is to introduce the new pensions/PBOP reconciling mechanism into the LDAC (id.). Bay State proposes three additional changes to the LDAC: (1) the Company has removed obsolete language referencing

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160 "Cherry picking" is the practice of a competitive gas supplier selecting those customers whose cost to serve is lower than the price charged by the local distribution company.

a two-year rate plan that was in place during the 1990's; (2) the provisions governing the SQ have been replaced with the provisions established in D.T.E. 99-84; and (3) the Company has removed provisions relating to recovery of LBR in accordance with the Company's proposal to recover LBR through the ABRAM (id., at 15).

b. Positions of the Parties

No party commented specifically on the proposed modifications to the CGAC or the LDAC, although we have elsewhere noted the Attorney General's opposition to reconciling pension/PBOP costs.

c. Analysis and Findings

In Section VII, the Department approved Bay State's proposal to adopt the SMBA gas cost allocation method. Accordingly, we accept the proposed modifications to the CGAC tariff that implement the SMBA. We have reviewed the most recent version of the proposed CGAC submitted in response to RR-DTE-172 and find that the Company has properly incorporated typographical and other minor revisions to the CGAC that the Company agreed to in the course of cross examination in this proceeding and we approve the modified tariff. We note however, that the CGAC references certain numbers that the Company indicated depend upon the outcome of these proceedings, specifically, sections 5.0 (9) and 6.0, dealing with local production and storage, LNG, and LPG costs, as well as bad debt expense (Tr. 19, at 3104; RR-DTE-172). The Company is directed to make any necessary adjustment to the referenced sections of its CGAC tariff in its compliance filing.

With regard to the proposed adjustments to the LDAC related to the two-year rate plan and the SQ provisions, the Department has reviewed these modifications and finds that they are

reasonable and necessary to update the tariffs, and they are hereby approved. As discussed in Section XI of this Order, the Department rejects the Company's proposal to recover LBR via the ABRAM. Accordingly, we direct the Company not to remove from the LDAC tariff provisions relating to LBR recovery.

D. Marginal Cost

1. Introduction

The Company filed a marginal cost study ("MCS") that included analyses of the increased costs that the Company would incur if it provided an additional unit of service (Exh. BSG/JLH-3, at 2). The use of the MCS in ratemaking results in a level and pattern of prices that promotes appropriate consumption decisions as well as an efficient allocation of societal resources (id. at 2-3). The MCS includes the calculation of the following components: (1) marginal distribution costs; (2) marginal commodity costs; (3) marginal production costs; and (4) marginal customer costs (id. at 3, 16).[161]

To calculate the marginal distribution cost, Bay State determined the marginal distribution capacity cost and the marginal distribution O&M cost, as well as various loading factors that represent administrative and other indirect costs. The Company computed its marginal distribution capacity costs based on (1) the long-run marginal cost of expanding the existing gas distribution system, and (2) the long-run marginal cost of adding main extensions

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[161] As we explain in Section VII.D.3 below, the marginal commodity costs, marginal production costs and marginal customer costs are not used for the purpose of designing base rates. Therefore, the Department will not address the results of these studies.

(id. at 9). Bay State used the "Prospective Additions" ("PA") approach to estimate the marginal distribution capacity costs (id. at 10-12).

Under the PA approach, the marginal cost of expanding the existing gas distribution system was based on a 10-year, forward-looking analysis prepared by the Company's engineering staff (id. at 11). The Company forecast the design day sendout and the main reinforcement costs during that period and divided the total main reinforcement cost by the increase in design day sendout to arrive at an estimated $199.33 per design day decatherm (id. at 11, Sch. JLH 3-2).

Under the PA approach, the marginal cost of adding main extensions was based on an analysis of historical main extension footage, load, and cost for the period 1984 to 2004 (Exh. BSG/JLH-3, at 11). According to the Company, Bay State only has data for investments in main extensions since 1984 (Exh. DTE 2-1).[162] Bay State divided total investment costs in main extensions during that period by the increase in design day sendout (Exh. BSG/JLH-3, Sch. JLH 3-2). The average incremental cost estimate was $256.33 per design day decatherm (Exh. BSG/JLH-3, at 11). In order to calculate the total distribution capacity unit cost, the Company summed the main reinforcement cost estimate of $199.33 and the main extension

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[162] To estimate investments in main extensions, Bay State employed data from internal cost accounting reports and judgments made by personnel reviewing those reports since the Uniform System of Accounts does not segregate gas mains investments into reinforcements, replacements and main extensions (Exhs. DTE 2-1; DTE 15-6; RR-DTE-93). The Company stated that it was impossible to develop meaningful estimates of cost data prior to 1984 since the Company does not retain internal cost accounting reports indefinitely. Therefore, the internal cost accounting reports were only available back to 1984 (Exhs. DTE 2-1; DTE 15-6).

cost estimate of $256.33, resulting in $455.66 per design day decatherm (Exh. BSG/JLH-3, at 11; Sch. JLH-3-2).

With respect to the marginal distribution O&M costs, Bay State indicated that maintenance costs are generally declining as cast iron and bare steel pipes are replaced by plastic pipes (Exh. BSG/JLH-3, at 13). According to Bay State, regressing unit cost on time[163] and correcting the equation for serial autocorrelation allowed the Company to develop a meaningful econometric specification (Exhs. DTE 15-15; RR-DTE-96). The Company used 29 years worth of data (1977-2004) (Exhs. BSG/JLH-3, Sch. JLH 3-4; DTE 2-3). The marginal O&M cost was estimated at $12.25 per design day decatherm (Exhs. BSG/JLH-3; Sch. JLH 3-9). The final step in the Company's analysis was to derive loading factors that represent administrative and other indirect cost and sum the various expenses (Exh. BSG/JLH-3, Sch. JLH 3-9). The total marginal distribution cost amounted $83.50 per design day decatherm (id.).

Pursuant to a request by the Department, the Company remodeled its marginal distribution capacity cost using regression analysis (Exh. DTE 15-5). The Company estimated marginal distribution capacity cost by fitting a quadratic function, using 29 years worth of data (1977-2004) (id.). The Company deflated the cost of investment in distribution plant using the GDP IPD deflator (id.). Bay State used the design day demand variable as the driver of

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163 The Company attempted several regression equations using annual distribution O&M costs, not unit costs, as the dependent variable, but could not develop a meaningful prediction equation (Exh. DTE 2-3; RR-DTE-96).

investments. The resulting marginal distribution capacity cost estimate was $475.26 per design day decatherm[164] (id.).

2. Company's Position

Bay State contends that the Company's MCS complies with the Department's directions in D.T.E. 02-24/25 and D.T.E. 03-40 concerning the preparation of a MCS (Exh. BSG/JLH-3, at 6; Bay State Brief at 157). Further, Bay State contends that it complied with the Department's econometric directives whenever possible, but not when there was not enough historical data available or when the interview process revealed that historical trends were not indicative of the future (Bay State Brief at 157, citing Exhs. DTE 2-1 to DTE 2-8; DTE 15-5 to DTE 15-16). No other party commented on this issue.

3. Analysis and Findings

Our review of the MCS developed by Bay State indicates that the MCS incorporates sufficient detail to allow full understanding of the methods used to determine the marginal cost estimates. In its MCS, the Company has included the determination of four cost components: (1) marginal distribution costs (capacity costs and O&M costs); (2) marginal commodity costs; (3) marginal production costs; and (4) marginal customer costs. The Department reviewed and evaluated two methods used to determine the marginal distribution capacity costs (a) the PA approach, and (b) in response to the Department's inquiry, a marginal distribution capacity cost using regression analysis.

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[164] The estimate of $475.26 is the result of computing the average of all the predicted marginal costs from 1977 through 2004 (Exh. DTE 15-5).

Our review of the Company's proposed marginal distribution capacity cost estimates based on the PA approach, indicates that such estimates were not calculated consistent with the Department directives as outlined in D.T.E. 02-24/25 and D.T.E. 03-40. In particular, we find that in computing the marginal capacity cost of main reinforcements and the marginal capacity cost of main extensions, the Company: (a) did not use an econometric analysis; (b) did not use multiple variable regression equations; and (c) did not perform appropriate tests to detect potential statistical problems (Exh. DTE 2-1).

Bay State argues that it has not complied with the Department's directives regarding the computation of the distribution capacity costs because (1) not enough historical data was available, and/ or (2) historical cost trends are not indicative of the future (id.). In particular, Bay State asserted that it did not use econometric analysis to estimate the marginal cost of main extensions because it had data available only from 1984 to 2004 and not 30 years worth of data (id.; Exh. DTE 15-6).

The Department acknowledges Bay State's lack of historical cost data for main extensions and main reinforcements costs. However, we find that the lack of segregated cost data of investments in mains does not justify the failure to comply with the Department's directives. We note that in order to estimate the marginal distribution capacity cost, it is not necessary for the Company to segregate cost data and estimate separately the marginal cost for main reinforcements and main extensions. Indeed, in directing companies to estimate the marginal distribution capacity cost, the Department has not required that marginal cost estimates be based on two cost components: main extensions and main reinforcements.

Regarding the Company's marginal cost estimate of main extensions, the Department notes that the reliance on segregated cost data may affect the reliability and accuracy of the Company's proposed marginal cost estimate for the following reasons. First, the Company's proposed marginal cost estimate of main extensions was based on a shorter time series cost data set. Bay State used 21 years instead of the recommended minimum of 30 years (see D.T.E. 02-24/25 (2002). Second, the Company's proposed marginal cost estimate of main extensions was derived from estimated cost data instead of actual data (Exhs. DTE 2-1; DTE 15-6).[165] The Company's unnecessary reliance on estimated data results in marginal cost estimates, which are not as accurate as estimates based on actual data.

Regarding the computation of the marginal cost of main reinforcements, we note that the Company used a 10-year forward looking approach, but did not use an econometric analysis. Bay State asserts that the future behavior of main reinforcement investments cannot be explained by historical behavior of main investment (Exhs. DTE 2-1; DTE 15-7). Further, Bay State argues that main reinforcement costs are very lumpy, and nearly impossible to predict (Exh. DTE 15-7). We disagree. Bay State was not required to forecast the investments in distribution costs but simply to estimate the marginal cost of distribution investments. The record evidence indicates that Bay State has failed to demonstrate both the need for a forward-looking engineering study to calculate marginal distribution costs, and that

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165 Main cost extension data were unavailable (Exh. DTE 15-6). The Company relied on internal cost accounting reports and judgments made by personnel reviewing these reports to segregate gas main investments (Exh. DTE 2-1).

the use of historical econometric analyses to compute the marginal cost of reinforcement would result in inaccurate estimates (Exh. DTE 15-8).

"[L]umpiness" of distribution investments would not justify the failure to comply with the Department's directives. We note that although Bay State contends that the costs of reinforcement are very lumpy and thus very difficult to forecast, the Company's proposed approach to estimate the marginal cost of main reinforcements relies explicitly on forecast reinforcement costs as well as a forecast design day sendout variable (Exh. BSG/JLH-3, at 11). Moreover, there is no evidence in the record to allow us to assess the reliability and accuracy of the Company's forecast.

In summary, the Department finds that the Company has failed to comply -- and has neither justified nor excused its failure -- with the Department's directives specified in D.T.E. 02-24/25 and D.T.E. 03-40. Therefore, the Department will not accept the Company's proposed marginal distribution capacity cost.

The Department notes that the Company developed a marginal distribution capacity cost based on an econometric analysis of plant investment (Exh. DTE 5-15). Our review of this method indicates that the Company has sufficiently documented its method of estimation. Additionally, the Department notes the econometric method employed by the Company is based on proven estimation techniques. The R-squared[166] of the regression equation was

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[166] The coefficient of determination R-squared is a measure of the fraction of the variance of the dependent or endogenous variable explained by the independent or exogenous variables.

0.98 and the t-statistics[167] were greater than 2.00, indicating that the estimates of the two explanatory variables used to derive the marginal cost estimate are statistically significant (RR-DTE-90). In addition, we note that the Company detected a serial autocorrelation problem in the regression equation by the Durbin-Watson statistic test[168] (id.). Bay State corrected for serial autocorrelation using the Cochrane-Orcutt method[169] (id.). After assessing the R-squared, t-statistics, and the application of the Cochrane-Orcutt method, the Department finds that the estimation of the marginal distribution capacity cost method complies with the Department's directives in D.T.E. 02-24/25 and D.T.E. 03-40. Further, we find that the marginal distribution capacity cost estimate is within an acceptable level of confidence. Therefore, the Department will accept the Company's marginal distribution capacity cost estimated from the econometric analysis.

In addition, the Department assessed the Company's marginal distribution O&M cost. Instead of deriving a marginal cost estimate, Bay State estimated the unit cost or an average cost estimate with respect to time. The Department notes that Bay State attempted but could

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167 The t-statistic is the ratio of the estimated coefficient value to its standard error. The t-statistic is used to test whether the coefficient of a variable equals zero. If the t-statistic exceeds two in magnitude, it is at least 95 percent likely that the coefficient is not zero.

168 A Durbin-Watson statistic test is a statistical testing procedure used to test for first-order autocorrelation in the error term.

169 The Cochrane-Orcutt iterative least squares procedure is a standard econometric technique used to address first order serial autocorrelation. The average correlation between residuals of consecutive periods is estimated and incorporated in the regression equation by transforming the dependent and independent variables of the equation. The coefficients of the independent variables are reestimated in an iterative fashion until the serial correlation in the residuals are removed.

not develop meaningful marginal cost estimates (Exh. DTE 2-3; RR-DTE-96). However, the unit cost regression equation displayed a statistically significant declining trend which describes the Company's actual behavior of the distribution O&M costs (RR-DTE-95). Therefore, we will accept the Company's proposed unit cost estimate as a proxy for an estimated marginal distribution O&M cost. In its next rate case, the Department directs the Company to identify the variables determining the level of distribution O&M costs and use them to develop a meaningful econometric specification to estimate the marginal distribution O&M cost.

Finally, the Department notes that in its MCS, the Company has included the calculation of four cost components: (1) marginal distribution costs; (2) marginal commodity costs; (3) marginal production costs; and (4) marginal customer costs. In view of the Department's unbundling initiatives in both the gas and electric industries, marginal commodity cost, marginal production cost and marginal customer costs are no longer used for purposes of rate design. Consequently, the Department directs the Company, in its next rate case, to file a MCS which shall only calculate the marginal distribution capacity costs and marginal distribution O&M costs.[170] In its compliance filing, the Department directs the Company to recalculate the total marginal distribution cost based on the findings in this section.

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[170] This directive shall apply, consistent with precedent development in the interval between now and those future rate filings, to all gas and electric companies in Massachusetts.

E. Rate Design

1. Introduction

The Company states that the initial revenue targets, which are set at the equalized rate of return for all of the Company's rate classes, were evaluated to determine if any customer class would receive an overall increase greater than six percent of its total test year revenue, excluding the shortfall due to the low-income discount (Exh. BSG/JAF-2, at 5). Bay State adds that any customer class above this amount was capped at six percent, and the remaining revenue increase was reallocated to the other rate classes (id.). The basis for this allocation was the ratio of each rate class's test year revenues to the total test year revenues of those classes that were below the six percent cap (id. at 6). The Company states that the employment of the six percent cap is consistent with past practice and Department precedent as the six percent cap limits bill impacts in general (id.).

Based on the results of the Company's COSS, no rate class is currently collecting its full embedded customer cost through its customer charge (id. at 10,14-15). According to the Company, almost every rate class's current customer charge is so far below its embedded costs that the Company is not able both to set the customer charges to collect embedded cost and at the same time to satisfy the Department's continuity goal (id.). The only exception being the G/T-43 and G/T-53 rate classes, which have a proposed customer charge that is set at 100 percent of embedded costs (id. at 15). Accordingly, to reduce intra-class subsidies and satisfy the Department's rate design goals, the Company proposes to phase in cost-based customer charges (id. 10, 14-15). As part of this phase-in process, the Company proposes to increase

each rate class's customer charge to between 25 percent and 100 percent of the fully embedded cost (id.).

Regarding the delivery charges, the Company proposes to simplify its rate structure where possible, by establishing single-step delivery charges (id. at 9-10). However, where it is not possible, as a result of a large portion of customer costs not being recovered through the customer charge, the Company proposes to establish a block rate that does not distort the price signal of the tailblock rate (id. at 11-12). The Company proposes to set the break between headblock and tailblock rates at a level that results in the usage of approximately 50 percent of customer bills terminating in the headblock and 50 percent in the tailblock (id. at 9).

When setting delivery rates, the Company set the second block rate as a multiplier of the unit marginal cost for each rate class (id. at 11). The Company used a multiplier of 1.80 to balance competing rate design goals (efficiency and continuity) (id.). The Company states that the second block rate should be set close to marginal cost to provide proper price signals for customers' consumption decisions (id.). However, the Company adds that setting the second block rate at or very close to marginal cost will cause disproportionately high bill impacts for low-use residential customers (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the proposed increases to the residential and small commercial rate classes will create onerous bill impacts (Attorney General Brief at 116). The Attorney General suggests that the Department either hold the customer charges for these rate

classes at their current level, or limit the increase to the overall increase granted to the Company for the residential heating class (id.).

The Attorney General also takes issue with the Company's proposed residential delivery rates (id. at 116-117). While the Company proposed block rates for the residential rate classes, the Attorney General requests that the Company provide a flat rate design (i.e., no block charges) for the residential rate classes (id. at 117). The Attorney General argues that a flat rate design for the residential rate classes not only would simplify rate design but would also provide lower bill impacts for all but those customers with higher than average use (id., citing Exh. AG-9-18; RR-DTE-122).

b. Company

Bay State argues that its proposed block rates for residential customers and flat rates for C&I customers appropriately allocate revenue requirement, cap class bill impacts, gradually increase customer charges to low-use customer classes, and simplify rate structure, where appropriate, all while managing the intra-class bill impacts and avoiding or minimizing the associated intra-class subsidization (Bay State Brief at 227). The Company argues that its proposed rate design is fair (id.). The Company states that it has proposed to simplify rates when possible (e.g., for the C&I rate classes), however, in cases where simplicity is not possible in light of other rate design goals, the Company has maintained its block rates (e.g., for the residential rate classes) (id.).

Bay State disagrees with the Attorney General's argument that the Department should direct the Company to implement a flat rate design for the residential classes (id. at 239). The Company argues that price signals are very important for residential customers and that flat

rates may not send the proper price signal to these customers (id.). The Company also argues that the Attorney General's claim that a flat residential rate mitigates the impact of a distribution rate increase when peak gas prices take effect is not accurate (id.). Bay State claims that in order to achieve such mitigation, the customer charge should increase, and the rate design should ensure that the head block is priced higher than the tail block price, which is just the opposite of averaging the head/tail block price in order to set flat rates (Bay State Brief at 239).

Bay State argues that its proposed residential customer charges are reasonable because they balance the Department's regulatory policy objective to minimize bill impacts and the need to move towards cost-based rates (id. at 229). The Company argues that lowering the proposed customer charge increases would create higher bill impacts for higher use customers within the rate class (id. at 238). In reference to the Attorney General's argument concerning the customer charges for small C&I customers, the Company states that lowering the customer charge for these customers could make flat rates less effective in terms of intra-class bill impacts and reasonable price signals (id.).

3. Analysis and Findings

Regarding the proper level to set the customer charge and delivery charges for each rate class, the Department will make this determination on a rate class by rate class basis, based on a balancing of our rate design goals, which are discussed above. The rate-by-rate analysis is discussed below.

The Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated on the basis of

equalized rates of return. See D.T.E. 03-40, at 384; D.T.E. 02-24/25, at 256; D.T.E.01-56, at 139; D.P.U. 92-210, at 214. This allocation method satisfies the Department's rate structure goal of fairness. However, the Department must balance its goal of fairness with its goal of continuity. To do this, we have reviewed the changes in total revenue requirements by rate class and the annual and seasonal bill impacts by consumption level within rate classes. Thus, to address interclass subsidization, no rate class shall receive an increase greater than 125 percent of the overall distribution rate increase approved in this Order.

The remaining revenue increase (i.e., the amount above the 125 percent cap) will be allocated based on the ratio of each class's base revenues to the total base revenues for these classes. The remaining revenue increase, will be recovered from those classes whose revenue requirement falls below the 125 percent rate cap.

F. Rate by Rate Analysis

1. Rate R-1 and Rate R-3 (Residential Non-Heating and Heating)

a. Introduction

Rate R-1 is available to all residential customers who do not have gas space-heating equipment, while Rate R-3 is available to all residential customers who have gas space-heating equipment. Both R-1 and R-3 require that a customer take service through one meter in a single building that contains no more than four dwelling units (Proposed M.D.T.E. No. 38; Proposed M.D.T.E. No. 40). The Company proposes to increase the monthly customer charge from $7.46 to $11.60 for Rate R-1, and from $7.47 to $12.10 for Rate R-3 (Exh. BSG/JAF-2, Sch. JAF 2-7, at 1-2).

The proposed R-1 delivery charge during the peak season is $0.2393 per therm for the first 12 therms consumed, and $0.1928 for each additional therm (Exh. BSG/JAF-2, Sch. JAF 2-7, at 2). The proposed R-1 delivery charge during the off-peak season is $0.2393 per therm for the first ten therms consumed, and $0.1928 for each additional therm consumed (id.).

The proposed R-3 delivery charge during the peak season is $0.3183 per therm for the first 125 therms consumed, and $0.2224 for each additional therm consumed (Exh. BSG/JAF-2, Sch. JAF 2-7, at 1). The proposed R-3 delivery charge during the off-peak season is $0.3183 per therm for the first 30 therms consumed, and $0.2224 for each additional therm consumed (id.). In addition, the Company proposes to increase the headblock size from 90 therms to 125 therms for the R-3 rate class (Exh. BSG/JAF-2, at 9).

b. Analysis and Findings

According to the Company's MCS, the total peak season marginal costs for Rates R-1 and R-3 are $0.0652 and $0.1156 per therm, respectively (Exh. BSG/JAF-2, Sch. JAF 2-1, at 11, line 290). According to the Company's COSS, the embedded customer charges for Rates R-1 and R-3 are $24.22 and $23.30 per month, respectively (Exh. BSG/JAF-2, Sch. JAF 2-2). Based on a review of marginal and embedded costs and the seasonal and annual bill impacts on customers, the Department finds that an R-1 Rate, designed with a $10.00 monthly customer charge satisfies continuity goals and produces bill impacts that are moderate and reasonable. Based on the R-3 marginal and embedded costs and seasonal and annual bill impacts, the Department finds that a $10.00 monthly customer charge satisfies continuity goals and produces bill impacts that are moderate and reasonable. However, based on simplicity goals, the Department directs the Company to modify its volumetric charges for the R-1 and

R-3 rate classes so that these rate classes are charged based on a flat rate structure. Such rate design will also satisfy continuity goals and produce bill impacts that are moderate and reasonable.[171] Therefore, the Department directs the Company to set the volumetric charges for Rates R-1 and R-3 to collect the remaining class revenue responsibility.

2. Rate R-2 and Rate R-4 (Residential Non-Heating and Heating Subsidized Rates)

Subsidized rates are available for all domestic purposes in individual private dwellings or in individual apartments. Eligibility for this rate is established upon verification of a customer's receipt of any means-tested public benefit program or verification of eligibility for the low-income home energy assistance program, or its successor program, for which eligibility does not exceed 175 percent of the federal poverty level based on a household's gross income, or other criteria approved by the Department (Proposed M.D.T.E. No. 39; Proposed M.D.T.E. No. 41; see also 220 C.M.R. § 14.03(2)(b)). The Company proposes that customers on Rates R-2 and R-4 continue to receive a 20 percent discount off the total charges for Rates R-1 and R-3, respectively using the GAF and LDAF in effect during the test year (Exh. BSG/JAF-2, at 12).

In establishing the delivery service rates for low-income customers, the Department has consistently found that distribution companies shall provide such customers a 40 percent discount to their delivery service rates. D.T.E. 03-40, at 388; D.T.E. 02-24/25, at 262. The

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[171] The tailblock rate proposed by the Company was 1.8 times the marginal cost (Exh. BSG/JAF-2, at 11). Because the proposed tailblock rate significantly exceeds marginal costs, this proposed rate would not send the proper price signal to customers, which is inconsistent with Department policy. See, e.g., D.P.U. 90-121, at 185-187 (1990); Colonial Gas Company, D.P.U. 90-90, at 5-7 (1990); D.P.U. 84-25 (1984).

discount rate approved by the Department has consistently been applied to the delivery service rates rather than the total rates because only the delivery service component of rates is discounted.

Bay State proposes to establish the delivery service rates for its low-income customers such that the low-income customers will receive a 20 percent discount off of the total charges of the non-discounted rates. Bay State's method of determining the subsidized rates is not consistent with Department precedent and may result in the low-income delivery service rates changing significantly from one rate case to the next because the rates would be dependent on the fuel prices in effect, which have been volatile. Customer on Rates R-2 and R-4 currently receive a 20 percent discount off of the customer charges and an overall 28 percent and 43 percent discount off of the delivery service charges for Rates R-1 and R-3, respectively (Exh. BSG/JAF-2, Sch. JAF 2-1, at 1). The discount level currently available to the R-4 rate class should not erode: accordingly, we direct that the future discount to the *delivery service* rates should either be the current level of discount or be 40 percent, whichever provides the greater benefit. Therefore, the Department directs the Company to set the customer charge and variable per therm charge for Rate R-2 at 40 percent below the Rate R-1 customer charge and variable per therm charge. For Rate R-4, the Department directs the Company to set the customer charge and variable per therm charge at 43 percent below the Rate R-1 customer charge and variable per therm charge.

3. Rate G/T-40 (C&I Low Annual Use/Low Load Factor)

Rate G/T-40 is available to C&I customers whose annual usage is less than 5,000 therms and whose peak usage is greater than or equal to 70 percent of annual use as determined by Company records and procedures (Proposed M.D.T.E. No. 42; Proposed M.D.T.E. No. 55).[172] The Company proposes to increase the monthly customer charge from $12.61 to $19.00 (Exh. BSG/JAF-2, Sch. JAF 2-7, at 4). The proposed delivery charge during the peak and off-peak season for Rate G/T-40 is $0.3090 per therm (id.).

According to the Company's MCS, the total peak season marginal cost for Rate G/T-40 is $0.1396 per therm (Exh. BSG/JAF-2, Sch. JAF 2-1, at 11, line 290). According to the Company's COSS, the embedded customer charge for Rate G/T-40 is $34.63 per month (Exh. BSG/JAF-2, Sch. JAF 2-2). Accordingly, based on a review of marginal and embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $16.00 monthly customer charge and a flat delivery charge for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. Therefore, the Department directs the Company to set the Rate G/T-40 customer charge at $16.00 and the volumetric charge to collect the remaining class revenue responsibility.

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[172] The Department notes that the wording in the "Characteristics of Customer" section of proposed M.D.T.E. No. 55 contains incorrect the usage characteristics for low annual use/low load factor customers. The Department directs the Company to revise this wording in its compliance filing as follows: substitute "usage of between 5,000 therms and 39,999 therms" with "usage of less than 5,000 therms".

4. Rate G/T-41 (C&I Medium Annual Use/Low Load Factor)

Rate G/T-41 is available to C&I customers whose annual usage is between 5,000 therms and 39,999 therms and whose peak period usage is greater than or equal to 70 percent of annual use as determined by Company records and procedures (Proposed M.D.T.E. No. 43; Proposed M.D.T.E. No. 56). The Company proposes to increase the monthly customer charge from $45.04 to $65.00 (Exh. BSG/JAF-2, Sch. JAF 2-7, at 6). The proposed delivery charge for all therms consumed during the peak season is $0.1920 per therm, and during the off-peak season is $0.1216 per therm (id.).

According to the Company's MCS, the total peak season marginal cost for Rate G/T-41 is $0.1255 per therm (Exh. BSG/JAF-2, Sch. JAF 2-1, at 11, line 290). According to the Company's COSS, the embedded customer charge for Rate G/T-41 is $82.80 per month (Exh. BSG/JAF-2, Sch. JAF 2-2). Based on a review of marginal and embedded costs, and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $65.00 monthly customer charge and a single step volumetric charge for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, in order to price the peak volumetric charge at a higher rate than the off-peak volumetric charge, the Company is directed to shift revenues such that the same ratio of peak to off-peak volumetric charges proposed by the Company is maintained, while collecting the remaining revenue responsibility from the volumetric charges. Therefore, the Department directs the Company to set the Rate G/T-41 charges accordingly.

5. Rate G/T-42 (C&I High Annual Use/Low Load Factor)

Rate G/T-42 is available to C&I customers whose annual usage is between 40,000 therms and 249,999 therms and whose peak period usage is greater than or equal to 70 percent of annual use as determined by Company records and procedures (Proposed M.D.T.E. No. 44; Proposed M.D.T.E. No. 57). The Company proposes to increase the monthly customer charge from $109.37 to $213.00 (Exh. BSG/JAF-2, Sch. JAF 2-7, at 8). The proposed delivery charge during the peak season is $0.1794 per therm for all therms consumed (id.). The proposed volumetric charge during the off-peak season is $0.0778 per therm for all therms consumed (id.).

According to the Company's MCS, the total peak season marginal cost for Rate G/T-42 is $0.1134 per therm (Exh. BSG/JAF-2, Sch. JAF 2-1, at 12, line 290). According to the Company's COSS, the embedded customer charge for Rate G/T-42 is $261.13 per month (Exh. BSG/JAF-2, Sch. JAF 2-2). Based on a review of marginal and embedded costs, and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $213.00 monthly customer charge and a single step volumetric charge for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, in order to price the peak volumetric charge at a higher rate than the off-peak delivery charge, the Company is directed to shift revenues such that the same ratio of peak to off-peak volumetric charges proposed by the Company is maintained while collecting the remaining revenue responsibility from the volumetric charges.

6. Rate G/T-43 (C&I Extra-High Annual Use/Low Load Factor)

Rate G/T-43 is available to C&I customers whose annual usage is greater than 250,000 therms and whose peak period usage is greater than or equal to 70 percent of annual use as determined by Company records and procedures (Proposed M.D.T.E. No. 45; Proposed M.D.T.E. No. 58). The Company proposes to increase the monthly customer charge from $298.53 to $781.00 (Exh. BSG/JAF-2, Sch. JAF 2-2). The proposed volumetric charge during the peak season is $0.0507 per therm for all therms consumed (Exh. BSG/JAF-2, Sch. JAF 2-1, at 16, Line 382). The proposed volumetric charge during the off-peak season is $0.0193 per therm for all therms consumed (id.). The proposed demand charge during the peak season is $2.1586 per therm of maximum daily gas usage (Exh. BSG/JAF-2, Sch. JAF 2-1, at 16, Line 385). The proposed demand charge during the off-peak season is $0.6713 per therm of maximum daily gas usage (Exh. BSG/JAF-2, Sch. JAF 2-1, at 16, Line 389).

According to the Company's MCS, the total peak season marginal cost for Rate G/T-43 is $0.1272 per therm (Exh. BSG/JAF-2, Sch. JAF-2-1, at 12, line 290). According to the Company's COSS, the embedded customer charge for Rate G/T-43 is $799.10 per month (Exh. BSG/JAF-2, Sch. JAF-2-2). Based on a review of marginal and embedded costs, and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $781.00 monthly customer charge, a single step volumetric charge for the peak and off-peak seasons and a single step demand charge for the peak and off-peak seasons satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, in order to price the peak volumetric and demand charges at a higher rate than the off-peak volumetric and demand charges, the Company is directed to shift revenues such that the same

ratio of peak to off-peak volumetric and demand charges proposed by the Company is maintained while collecting the remaining revenue responsibility from these two charges.

7. Rate G/T-50 (C&I Low Annual Use/High Load Factor)

Rate G/T-50 is available to C&I customers whose annual usage is less than 5,000 therms and whose peak usage is less than 70 percent of annual use as determined by Company records and procedures (Proposed M.D.T.E. No. 46; Proposed M.D.T.E. No. 59). The Company proposes to increase the monthly customer charge from $12.61 to $19.00 (Exh. BSG/JAF-2, Sch. JAF 2-7, at 3). The proposed delivery charge during the peak and off-peak season for Rate G/T-50 is $0.2818 per therm (id.).

According to the Company's MCS, the total peak season marginal cost for Rate G/T-50 is $0.0683 per therm (Exh. BSG/JAF-2, Sch. JAF-2-1, at 11, line 290). According to the Company's COSS, the embedded customer charge for Rate G/T-50 is $42.57 per month (Exh. BSG/JAF-2, Sch. JAF 2-2). Based on a review of marginal and embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $16.00 monthly customer charge and a flat delivery charge for the peak and off-peak seasons satisfies continuity goals and produces bill impacts that are moderate and reasonable. Therefore, the Department directs the Company to set the Rate G/T-50 customer charge at $16.00 and the volumetric charge to collect the remaining class revenue responsibility.

8. Rate G/T-51 (C&I Medium Annual Use/High Load Factor)

Rate G/T-51 is available to C&I customers whose annual usage is between 5,000 therms and 39,999 therms and whose peak period usage is less than 70 percent of annual use as determined by Company records and procedures (Proposed M.D.T.E. No. 47; Proposed

M.D.T.E. No. 60). The Company proposes to increase the monthly customer charge from $45.04 to $65.00 (Exh. BSG/JAF-2, Sch. JAF 2-7, at 5). The proposed volumetric charge for all therms consumed during the peak season is $0.1774 per therm for Rate G/T-51, and during the off-peak season is $0.0826 per therm (id.).

According to the Company's MCS, the total peak season marginal cost for Rate G/T-51 is $0.0643 per therm (Exh. BSG/JAF-2, Sch. JAF 2-1, at 11, line 290). According to the Company's COSS, the embedded customer charge for Rate G/T-51 is $89.22 per month (Exh. BSG/JAF-2, Sch. JAF 2-2). Based on a review of marginal and embedded costs, and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $65.00 monthly customer charge and a single step volumetric charge for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, in order to price the peak volumetric charge at a higher rate than the off-peak volumetric charge, the Company is directed to shift revenues such that the same ratio of peak to off-peak volumetric charges proposed by the Company is maintained while collecting the remaining revenue responsibility from the volumetric charges. Therefore, the Department directs the Company to set the Rate G/T-51 charges accordingly.

9. Rate G/T-52 (C&I High Annual Use/High Load Factor)

Rate G/T-52 is available to C&I customers whose annual usage is between 40,000 and 249,999 therms and whose peak period usage is less than 70 percent of annual use as determined by Company records and procedures (Proposed M.D.T.E. No. 48; Proposed M.D.T.E. No. 61). The Company proposes to increase the monthly customer charge from $109.37 to $213.00 (Exh. BSG/JAF-2, Sch. JAF 2-7, at 7). The proposed volumetric charge

during the peak season is $0.1682 per therm for all therms consumed (id.). The proposed volumetric charge during the off-peak season is $0.0657 per therm for all therms consumed (id.).

According to the Company's MCS, the total peak season marginal cost for Rate G/T-52 is $0.0543 per therm (Exh. BSG/JAF-2, Sch. JAF 2-1, at 12, line 290). According to the Company's COSS, the embedded customer charge for Rate G/T-52 is $307.22 per month (Exh. BSG/JAF-2, Sch. JAF 2-2). Based on a review of marginal and embedded costs, and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $213.00 monthly customer charge and a single step volumetric charge for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, in order to price the peak volumetric charge at a higher rate than the off-peak volumetric charge, the Company is directed to shift revenues such that the same ratio of peak to off-peak volumetric charges proposed by the Company is maintained while collecting the remaining revenue responsibility from the volumetric charges.

10. Rate G/T-53 (C&I Extra-High Annual Use/High Load Factor)

Rate G/T-53 is available to C&I customers whose annual usage is greater than 250,000 therms and whose peak period usage is less than 70 percent of annual use as determined by Company records and procedures (Proposed M.D.T.E. No. 49; Proposed M.D.T.E. No. 62). The Company proposes to increase the monthly customer charge from $298.53 to $781.00 (Exh. BSG/JAF-2, Sch. JAF 2-2). The proposed volumetric charge during the peak season is $0.0507 per therm for all therms consumed (Exh. BSG/JAF-2, Sch. JAF 2-1, at 16, line 382). The proposed volumetric charge during the off-peak season is $0.0193 per therm for all therms

consumed (Exh. BSG/JAF-2, Sch. JAF 2-1, at 16, line 385-387). The proposed demand charge during the peak season is $2.1586 per therm of maximum daily gas usage (Exh. BSG/JAF-2, Sch. JAF 2-1, at 16, line 388). The proposed demand charge during the off-peak season is $0.6713 per therm of maximum daily gas usage (Exh. BSG/JAF-2, Sch. JAF-2-1, at 16, line 389).

According to the Company's MCS, the total peak season marginal cost for Rate G/T-53 is $0.0618 per therm (Exh. BSG/JAF-2, Sch. JAF 2-1, at 12, line 290). According to the Company's COSS, the embedded customer charge for Rate G/T-53 is $762.87 per month (Exh. BSG/JAF-2, Sch. JAF 2-2). Based on a review of marginal and embedded costs, and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $781.00 monthly customer charge, a single step volumetric charge for the peak and off-peak seasons and a single step demand charge for the peak and off-peak seasons satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, in order to price the peak volumetric and demand charges at a higher rate than the off-peak volumetric and demand charges, the Company is directed to shift revenues such that the same ratio of peak to off-peak volumetric and demand charges proposed by the Company is maintained. Finally, to set volumetric and demand charges, the Company is directed to maintain the same ratio of volumetric and demand charges as proposed by the Company while collecting the remaining revenue responsibility from these two charges.

11. Rate L (Outdoor Gas Lighting)

Rate L is available to all customers for unmetered gas service for a standard outdoor gaslight (id.). Rate L is only open to customers taking service under this rate as of December 14, 1979 (id.). The Company proposes to decrease the monthly charge from $3.32 to $2.58 per month per light (id. at 13-14). The Company determined this new rate based on the results of its COSS (id. at 14).

Because this service is unmetered and based upon the principle of simplicity in rate design, the Department finds the Company's method for determining its proposed rate to be acceptable. Accordingly, the Department directs the Company in its compliance filing to set the Rate L monthly charge to collect the Rate L revenue responsibility.

G. Recovery of Low-Income Discount

1. Introduction

Bay State proposes to continue to offer low-income customers a 20 percent discount off of their delivery service rates (id. at 12). The Company proposes to allocate the shortfall from providing low-income discount rates to all rate classes based on the class's allocated share of distribution rate base (id.). The Company has also proposed to file for recovery in its LDAC of additional lost revenues that stem from higher participation rates in the Company's low-income discount rate resulting from the file matching program being undertaken as a result of D.T.E. 01-106-B (Tr. 19 at 2984-2985).

2. Positions of the Parties

a. Attorney General

Although the Attorney General supports the Company's efforts to continue to offer a discount to low-income customers, he does take issue with how the subsidy is recovered in rates (Attorney General Brief at 120-121). The Attorney General references the Department's 2004 Order concerning a computer-matching program that has been established, to demonstrate that currently companies recover a portion of the low-income discount through base rates and a portion through the LDAC (for gas companies) (id. at 120, citing Low-Income Discount Participation Rate, D.T.E. 01-106-B (2004)). The Attorney General argues that for administrative ease and in support of a uniform application of the Department's low-income policies, the Department should require the Company to revise its rate design and tariff proposals to provide for the full recovery of the Department approved low-income discount through the Company's LDAC (Attorney General Brief at 121). The Attorney General states that collecting the discount costs through the LDAC will permit the reconciliation of actual discount costs that may vary over time as the level of eligible customers changes (id. at 119).

b. Company

The Company argues that its use of the distribution rate base allocator for the assignment of the low-income revenue shortfall is consistent with Department precedent (Bay State Brief at 230, citing D.T.E. 03-40; D.P.U. 95-52/104; and D.P.U. 92-111). Regarding the Attorney General's argument that the discount revenues be removed from base rates and recovered through the LDAC, the Company contends that this issue should be resolved as part of the Department's pending investigation in D.T.E. 01-106-B (Bay State Brief at 227 n.53). Bay State argues that, in the meantime, the Company's proposal for allocating the low-income discount should be approved (id., citing Exh. BSG/JAF-2, at 12).

3. Analysis and Findings

In D.T.E. 01-106-B at 10, n.4, the Department stated:

> In each company's next rate case, the Department will consider whether to establish a fully-reconciling mechanism to collect the entire revenue shortfall from discount rates or whether it may be more appropriate to resume collecting this shortfall from all customers through base rates.

In addition, in D.T.E. 01-106-C/05-55/05-56, at 11 (2005), the Department stated, "[c]ompanies will recover costs through the [Residential Assistance Adjustment Factor] until their next general distribution base rate case." We also noted in a footnote:

> . . . that G.L. c. 164, § 94 rate proceedings are well underway or are pending filing for Bay State and NSTAR, respectively. Some flexibility, we anticipate, may be necessary to reflect the instant Order as it affects those companies' rate proceedings.

D.T.E. 01-106-C/05-55/05-56, at 11, n.5.

It was reasonable for the Company to file for recovery of the low-income revenue shortfall as it did in this proceeding, because the Department had made no decisions regarding the cost recovery of this revenue shortfall as of the date of the filing of the rate case. However, the Department has now resolved the issue of cost recovery for the low-income revenue shortfall. See D.T.E. 01-106-C/05-55/05-56.

In the past, the Department has directed companies to place a representative level of the low-income revenue shortfall in base rates, which created a financial disincentive for the companies to aggressively enroll customers because as more customers are enrolled, the level of the low-income revenue shortfall increases. However, the amount recovered through base rates does not increase. In its Order in D.T.E. 01-106-C, the Department partially rectified

this situation by allowing companies to recovery not only the low-income revenue shortfall that is embedded in their base rates, but also any additional low-income revenue shortfall that has resulted from increased participation in low-income rates since July 1, 2005, regardless of how the new low-income customers were enrolled (i.e., through traditional outreach or through the computer-matching program). However, the most effective means by which to remove any financial disincentive is to allow Bay State dollar-for-dollar recovery of its low-income revenue shortfall. Consequently, the Department directs the Company to remove the entire low-income revenue shortfall from base rates and instead recover the entire low-income revenue shortfall in the LDAC. On a going forward basis, the recovery of the low-income revenue shortfall will coincide with the calculation of the LDAC and will be fully reconciling.[173] Therefore, in its compliance filing, the Company shall remove the recovery of the low-income revenue shortfall from base rates. The Company shall also, in its compliance filing, file a revised LDAC tariff to include the recovery of the low-income revenue shortfall on a reconciling basis. In addition, the Company shall file an amendment to its LDAC filing to incorporate the recovery of the entire low-income revenue shortfall through the LDAC.

VIII. TERMS AND CONDITIONS

A. Introduction

Bay State has proposed several modifications to the Company's Terms and Conditions. In particular, Bay State proposes to institute: (1) to modify the Company's existing

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[173] The Department notes that for the period from July 1, 2005 through the date of this Order the Company should treat the recovery of the low-income revenue shortfall in a way consistent with the method of recovery specified in D.T.E. 01-106-C.

Interruptible Transportation Agreement ("ITA"); (2) to eliminate the Interruptible Standby Gas Supply Service; (3) to modify several elements of the Company's Distribution and Default Service Terms and Conditions, (4) assign capacity to grandfathered transportation customers; (5) a new Dual Fuel Provision; and, (6) changes to service fees.

B. Company's Proposal

1. Interruptible Transportation

The Company proposes several changes to its ITA. In particular, the Company proposes to formalize the winter curtailment period during which interruptible service will not be available (Exh. BSG/JAF-3, at 6). In addition, the Company proposes several changes that clarify the various aspects of the interruptible service agreement and the roles of the respective parties under various situations (id.).

The Company's proposed curtailment period spans from December 1 through March 31 of each year (id.). During this period, interruptible customers are responsible for securing alternative fuels (id. at 7). The Company states that the proposed curtailment period is an important tool for Bay State in protecting its ability to deliver service to firm customers when extreme weather conditions occur (id.). The Company further states that absent this winter curtailment, interruptible customers could avoid adequate preparations for periodic curtailments and take emergency gas in lieu of curtailing operations (id.).

In addition to the curtailment period, the Company's proposed changes to the ITA, include the following: (1) modifications to the Conditions Precedent for becoming an interruptible customer; (2) inclusion of a two-hour notice for interruption or curtailment; (3) penalties for unauthorized usage; (4) a limitation of liability disclaimer; (5) prohibition of

use of interruptible gas for firm uses; and (6) the Company's ability to access the customer's premises (id. at 8-9).

Finally, the Company's proposal completely unbundles interruptible sales from interruptible transportation service (id. at 9). Interruptible customers will continue to have the option of purchasing commodity from Bay State; however, the point of purchase will be located at the city-gate rather than the customer's meter (id.). The Company states that all of its interruptible sales customers entered into agreements prior to the issuance of Interruptible Transportation/Capacity Release DPU 93-141-A (1996) and, therefore, were not subject to the directives of the Department's 1996 decision that only applied to new customers (id. at 10).

2. Interruptible Standby Gas Supply Service

The Company proposes to eliminate its tariffs governing Interruptible Standby Gas Supply Service (id. at 9). The Company states that the continued evolution of competitive supply services, has rendered this service otiose (id.). Finally, the Company states that there are no customers taking this service and, therefore, proposes to eliminate the existing tariffs M.D.T.E. No. 19 and M.D.T.E. No. 20 to simplify its service offering id.).

3. Distribution and Default Service Terms and Conditions

Bay State has proposed three modifications to its present Distribution and Default Service Terms and Conditions (id. at 10). In particular the Company proposes: (1) a change in section 5.5 of the Terms and Conditions to clarify that customers may sign a "Cromwell Waiver;"[174] and (2) a change in the cash-out mechanism which will allow the Company and

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[174] A Cromwell Waiver permits a customer to indicate service at a new address if the (continued…)

non-daily metered transportation customers to true-up over- and under-deliveries on a monthly basis (id. at 11).

4. Grandfathered Transportation Customers

The Company has also proposed new language that would affect the Company's grandfathered transportation customers (Tr. 13, at 2165, 2173-2174).[175] In particular, the Company proposes to assign capacity to those grandfathered transportation customers who, on a critical day, consume natural gas outside the permissible bandwidth (Tr. 13, at 2167; Exh. BSG/JAF-3-1, Sections 11.6.3; 13.3.7; and 11.3.47). The Company states that the proposed capacity assignment is in response to the Department directive in D.T.E. 02-75-A (2004).[176] The Company has not developed a system under which it will have the ability to monitor the usage of its grandfathered customers and recognizes that it has not fully complied with the Department's directives in D.T.E. 02-75-A (Tr. 13, at 2165, 2173-2174).

5. Dual-Fuel Provision

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174 (…continued)
customer has a preexisting balance with the Company for service at a different location (Exh. BSG/JAF-3, at 11). To receive service at the new location, the customer must agree to have the arrearage transferred to the new account (id.).

175 A grandfathered transportation customer is one who is not subject to mandatory capacity assignment.

176 In D.T.E. 02-75-A, the Department directed Bay State to: (a) notify and remind all of its grandfathered customers that unauthorized overtakes are subject to penalties; (b) implement a system under which the Company will have the ability to monitor the usage of its grandfathered customers; and (c) submit a report to explain how the system, referenced in (b) above, will work. D.T.E. 02-75-A at 7.

Bay State proposed a Dual-Fuel Provision that would impose a minimum take requirement on the Company's sales and transportation commercial and industrial customers[177] who have dual-fuel capability and have annual usage of 5,000 therms or more (Exh. BSG/JAF-3, at 5). Bay State notes that the proposed provision ensures that customers reimburse the Company for an equitable level of the costs of providing reliable service over the course of the year (id.).

Bay State's proposal is based on a minimum annual distribution revenue requirement similar to the off-tariff contracts (Exh. DTE 7-19). According to the Company, Bay State, either with the customer's assistance or solely based on historical gas usage, would determine the customer's peak day use (id.). The minimum commitment or take requirement will be based on each customer's peak day usage (id.). If the customer does not meet the annual minimum commitment, because it is using its alternate fuel, it will be responsible for paying an amount equal to the deficiency (Exh. BSG/JAF-3, at 5-6). The Company states that dual-fuel customers would continue to benefit from the ability to engage in economic fuel switching; however, the costs of reliability of Bay State's firm service would be recovered equitably (id. at 6). The Company's long-run marginal cost, as approved in this proceeding and adjusted for inflation at GDP-PI, will be the basis for determining each customer's payment in the event that the customer does not take the minimum requirement under the tariff (Exh. DTE 7-19). In

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[177] The Company excluded the G-40, G-50, T-40, and T-50 commercial and industrial customers (Exh. BSG/JAF-3, at 5). The Company excluded these rate classes because of the large number of customers in these rate classes and the small number of customers who may be dual-fuel customers. The Company further indicated that the small size of these customers would not impose a financial or operational burden on Bay State (Exh. DTE 7-15).

response to an Attorney General record request, Bay State estimates that if all 81 dual-fuel customers the Company was able to identify agreed to the Company's Dual-Fuel Provision, the Company's rate year revenues will increase by $203,841 (RR-AG-57).

The Company states that its distribution rates are delivery and are intended to recover the Company's fixed costs assuming that customers served under those rates are "full requirement customers" (Exh. BSG/SAF-3, at 4). The Company defines full requirement customers as firm customers who use natural gas for all of their heating and non-heating requirements (Exh. BSG/JAF-3, at 3). The Company's proposal will affect only those customers who have installed dual-fuel equipment in order to benefit from switching when there is a difference in commodity fuel costs (Exh. BSG/JAF-3, at 3). According to the Company, when dual-fuel firm customers switch from natural gas to an alternative fuel, they are not making a contribution towards Bay State's fixed costs and variable charges (id.). However, the Company incurs fixed costs in order to ensure that it provides reliable service over the course of the year (id. at 5). In addition, Bay State states that when dual-fuel customers switch from an alternative fuel to natural gas, especially on a peak day or critical day, the Company may end up either having insufficient supply for its firm full requirements sales customers or insufficient capacity on the local system for its firm full requirements distribution customers (Tr. 10, at 1741). Finally, the Company indicated that as a result of its proposal, it expects that some of the dual-fuel customers may elect to leave Bay State's system (id. at 1758).

6. Service Fees

The Company proposes to change the fees associated with Account Reactivations, Meter Tests and Warrants (Exh BSG/JAF-1, at 37). The Company also proposes to add a new Locksmith fee (id.).

Bay State proposes to increase the Account Reactivation Fee from $15 and $20 to $20 and $30 for services during and after business hours, respectively (id. at 38). The Company contends the increase is intended to reflect reasonable costs associated with account reactivation (id.). Regarding the Account Reactivation fee, Bay State's analysis indicates that the actual cost for reactivating an account is $22.59 and $32.55 for regular and after business hours, respectively (Exh. BSG/JAF-1-7, at 2).

Presently, the Company's Meter Test fee is set at $10.00 (Exh. BSG/JAF-1, at 39).[178] Bay State conducted an analysis which indicated the average cost for testing a meter to be $67.58 (Exhs. BSG/JAF-1-8; BSG/JAF-1, at 39). The Company proposes to increase the current fee to $50.00 (Exh. BSG/JAF-1, at 39).

Bay State proposes to change the Warrant fee to establish a direct pass through of costs associated with obtaining a warrant (id. at 40).[179] The Warrant fee is currently $35, which is the cost assessed by the Sheriff's Department in the Company's Springfield Division (id.). The Company states that the cost is actually $40 per warrant in both the Brockton and

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178 The meter test fee is payable by a customer who requests his or her meter to be tested, and only if the meter tests within a two percent accuracy (Exh DTE-10-1).

179 Warrant fees are assessed to the Company when Bay State requires a warrant to enter a customer's residence (Exh. BSG/JAF-1, at 40).

Lawrence Divisions (id.). The Company does not propose a set fee; rather the Company proposes to change the wording of the tariff to allow the Company to recover the cost assessed by the local authority to the Company to obtain the warrant (id.).[180]

Finally, the Company proposes to implement a Locksmith fee of $40.[181] The Company states that Locksmith fees vary by vendor, so the proposed fee reflects the average cost for obtaining locksmith service in the test year (meter at 41). The Company states this fee would be charged to those customers whose locations were accessed through the use of the locksmith service, with the associated revenue offsetting the costs incurred by the Company (id.; Exh. DTE-10-3). The Company has provided revenue adjustments that reflect the proposed fees in Schedules JAF-1-7 (Account Reactivation fee), and JAF-1-9 (Warrant and Locksmith fees) (Exh BSG/JAF 29-41).

C. Positions of the Parties

1 Grandfathered Transportation Customers

a. AIM

AIM argues that the proposed changes to the Company's Terms and Conditions in regard to grandfathered customers would expose grandfathered transportation customers to a full year's worth of capacity charges in addition to the penalty a customer would pay for an overtake on a single day (AIM Brief at 2). AIM argues that although existing penalty

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180 Bay State proposes to replace the current fee with the following language: "Actual cost assessed to the Company by the servant authorized by the Court to serve the warrant" (Exh. BSG/JAF-1, at 40).

181 The Company incurs costs for locksmith service to gain access to its meters in certain locations (Exh. BSG/JAF-1, at 41).

provisions for overtakes are appropriate, the proposed change in the tariff would be an additional and unfair burden on commercial and industrial customers and should, therefore, be rejected by the Department (id.).

b. Company

In response to AIM's argument, the Company maintains that an overtake on a single day, especially on a peak day, demonstrates that grandfathered transportation customers impose a risk to firm service (Bay State Reply Brief at 55). According to Bay State, the Company's proposal addresses the risk by allowing Bay State to manage the capacity required to ensure service when there is under-delivery to such customers (id.).

2. Dual-Fuel Provision

a. Attorney General

The Attorney General does not oppose the Company's proposed Dual-Fuel Provision. Rather, the Attorney General focuses on the treatment of the revenues that would be generated if the Company's proposal went into effect (Attorney General Brief at 52). The Attorney General argues that the revenues generated by the Company's proposal are known and measurable and, as such, the Department precedent as established in D.T.E. 02-24/25 and D.T.E. 03-40 should apply (id.). In particular, the Attorney General proposes that the Company's revenue requirement be reduced by $203,841 for the increased revenues related to the Company's proposed dual-fuel provisions (id.).

b. DOER

DOER argues that the special provision for dual-fuel customers should be rejected (DOER Brief at 11). DOER contends that the Company has not provided evidentiary support for the new charge (id.). DOER further argues that even if the Company had provided support regarding the costs and revenues associated with dual-fuel customers, the Department should investigate the broader energy policy implications of the Company's proposal (id. at 12). DOER asserts that dual-fuel customers that switch to alternative fuels during the winter heating season make additional supplies available, and reduce the need for Bay State to purchase supplies at potentially high prices during peak times (id., citing Exh. DOER-1, at 11). DOER concludes that the Company has not shown that dual-fuel customers cause costs to be shifted to other customers, when it is possible that the dual-fuel customers provide a benefit to firm customers on the system (DOER Brief at 12).

c. MOC

The MOC urges the Department to deny the Company's proposed special provision for dual-fuel customers (MOC Brief at 15). Similar to DOER, MOC argues that Bay State has not adequately supported its claim that the "provision will more fairly share the costs of firm service among customers and could reduce some volatility in revenues to the Company" (id. at 16).

d. AIM

AIM argues that the Company's proposal was created without any survey or discussion with customers (AIM Brief at 2, citing Exh. AG 9–32). Similarly, AIM argues that the Company developed the proposed Dual-Fuel Provision without any empirical evidence that

switching by dual-fuel customers causes system problems (AIM Brief at 2, citing RR-DTE-77). AIM asserts that the ability of an industrial customer to burn an alternative fuel during high gas demand periods benefits the Company and all customers attached to the distribution system (AIM Brief at 2). In conclusion, AIM claims that the Company's proposal is financially motivated and is an unfair and unjustified burden on industrial customers and, as such, should be rejected by the Department (id.).

e. Company

The Company argues that its proposed Dual-Fuel Provision is a reasoned approach to achieving fairness between firm customers that have dual-fuel capability and those that do not (Company Brief at 216). In addition, the Company argues that Bay State's interest is in maintaining system integrity and reliability and in ensuring that dual-fuel customers bear the true cost to serve them (Company Reply Brief at 55). The Company emphasizes that dual-fuel customers will be required to make a payment only if their usage falls below the minimum take requirement (Company Brief at 217, citing Exh. BSG/JAF-3, at 5-6). Finally, the Company argues that the Department has approved a similar tariff for NSTAR Gas Company (Company Brief at 216).

In response to DOER and MOC, Bay State argues that the Company used the Department's standard of long-run marginal cost in requiring a minimum annual revenue for providing firm distribution service (Company Brief at 66, citing Exh. DTE 7-19). The Company asserts that its calculation of the revenues, had the proposal been in effect, does not constitute known and measurable revenues (Company Brief at 66). Bay State further argues that the Attorney General's interpretation of the Department's standard is incorrect (id.).

According to Bay State, an estimate of future recovery based on a tariff that was not in effect is neither known nor measurable (id.). Bay State claims that any revenue that may be generated by the new Dual-Fuel Provision is (1) the result of the ebb and flow of ratemaking, and (2) not designed to raise total revenue for the Company (id.). Rather, it is designed to permit dual-fuel customers to contribute to the fixed capacity costs from which they benefit (id.).

In response to DOER, the Company notes that the intent of Bay State's proposal is to ensure recovery of distribution related revenues from its firm customers (id. at 67). Therefore, Bay State argues, DOER's suggestion that freed up commodity could reduce the demand cost is faulty (id.).

D. Analysis and Findings

The Department notes that the only comments received were regarding the Company's proposed capacity assignment to grandfathered transportation customers, and the Dual Fuel Provision. The Department has reviewed and evaluated the proposed changes outlined above and with the exception of the provision regarding grandfathered customers, the Dual-Fuel Provision, and the Meter Test Fee, which are discussed in more detail, below, finds them appropriate and, therefore, approves them.

1. General Modifications to Terms and Conditions

The Department notes that Bay State's proposed changes to its Interruptible Sales and Transportation service are consistent with the directives established in D.P.U. 93-141-A, and thereby approves them.

Regarding the Company's proposal to eliminate the Interruptible Standby Gas Supply Service, the Department notes that currently there are no customers receiving service under

this rate. Interruptible Standby Gas Supply Service was a needed product prior to the unbundling of interruptible sales and transportation. However, today's availability of natural gas, at competitive rates, from an abundance of gas suppliers and retail agents has rendered this service obsolete. The Department approves the termination of the Interruptible Standby Gas Supply Service.

Similarly, the Company's proposals regarding modifications to Bay State's Distribution and Default Service Terms and Conditions in order streamline and facilitate service are hereby approved.

2. Service Fees

Regarding the fees discussed above, the Company has demonstrated that the proposed increases to the Account Reactivation fee are cost based and reflect costs actually incurred by the Company. Similarly, Bay State's proposal to change the language associated with the Warrant fee allows the Company to collect the costs it incurs for serving a warrant. The Company's proposal to implement Locksmith fees allows the Company to recover the costs it incurs when it attempts to access it meters at individual locations. Having reviewed the Company's proposed fees, the Department finds that Bay State appropriately adjusted its test year revenues. Accordingly, the Department approves the proposed modifications to the Account Reactivation Fee, Warrant Fee, and the proposed Locksmith Fee.

With respect to the Meter Test Fee, the Company concedes that the proposed increases to the Meter Test Fee are below cost and do not reflect costs actually incurred by the Company. While the Department accepts that a gradual adjustment to fees set according to cost can be advisable, the Department finds that increasing the fee from $10.00 to $50.00 is

too large of an increase in a single step and, therefore, violates our own continuity of rates goal. The Department finds a fee of $30.00 provides a reasonable balance of our continuity and efficiency goals. Therefore, we approve a Meter Test Fee of $30.00.

3. Grandfathered Transportation Customers

Regarding the proposal to assign capacity to grandfathered transportation customers, the Department notes that the Company's proposal is incomplete. In D.T.E. 02-75-A, the Department explicitly directed the Company to implement a system under which the Company will have the ability to monitor the usage of its grandfathered customers. The Company has not developed such a method and is unable to appropriately assign costs it incurs on a critical day to its grandfathered transportation customers, if indeed these customers cause the Company to incur costs.[182] The record evidence indicates that Bay State's proposal is incomplete (Tr. 13, at 2165, 2174). Bay State has indicated that it would not oppose a conditional approval of the proposal prohibiting implementation until Bay State has fully complied with the Department directives in D.T.E. 02-75-A (id. at 2178).

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[182] Bay State has not developed a mechanisms to monitor the consumption of grandfathered transportation customers. In particular, the Company acknowledged that there are several steps it could take to complete its proposal. Bay State indicated that it: (a) could assume that every transportation customer in an aggregation pool contributed to the under-deliveries (Tr. 13, at 2175); or (b) require the supplier to indicate how the daily nominations are divided within each supplier's pool. However Bay State indicated that this approach works best with grandfathered transportation customers who have daily meters. For those transportation customers who do not have daily meters, the Company would have to calculate their contributions to overtakes based on their Average Transportation Volumes. (id. at 2175-2176). Finally, Bay State indicated that this proposal is better than not submitting anything, but certainly not as good as it would have been had Bay State had the luxury of time to prepare a complete proposal (id. at 2177).

Therefore, the Department rejects Bay State's modifications to its Terms and Conditions regarding to grandfathered transportation customers. However, as we described in D.T.E. 02-75-A, the opportunity exists for grandfathered transportation customers to threaten Bay State's distribution system on a critical day. D.T.E. 02-75-A at 6. The Department directs Bay State to submit, for Department review, a complete proposal for monitoring the overtakes by grandfathered transportation customers that addresses the directives in D.T.E. 02-75-A, by March 31, 2006. As we are rejecting the Company's proposal we need not address AIM's comments.

4. Dual-Fuel Provision

Regarding the Company's Dual Fuel Provision, the Department has to determine whether it will generate excess revenues for Bay State (i.e., additional revenues that have not been taken into consideration in developing the Company's proposed firm rates). In Commonwealth Gas Company, D.P.U. 91-60 (1991), the Department approved a dual-fuel provision for Commonwealth Gas Company ("ComGas"), the predecessor in name of NSTAR Gas Company. In approving that provision, the Department noted that ComGas' proposed tariff was identical to what the Department had approved in ComGas' previous rate proceeding in D.P.U. 87-122 (1987). In its 1987 decision, the Department found that "even if [a dual-fuel customer] takes gas only sporadically, the customer may impose virtually the same level of fixed costs upon the system as if it were a full requirements customer." D.P.U. 87-122, at 238.

DOER argues that switching to an alternative fuel by dual-fuel customer, frees up gas to be used by the Company's remaining firm customers. This notion is fundamentally flawed

in that it assumes that dual-fuel customers purchase natural gas solely from Bay State,[183] and will switch to an alternative fuel during the peak day or a cold snap, thereby freeing up quantities of gas that can be used for system integrity. However, the Company's proposal (a) does not differentiate between sales[184] and transportation customers, and (b) is intended to address the need to maintain system integrity when dual-fuel customers switch from another fuel to natural gas. The tariff currently in effect does not ensure that Bay State will recover its cost of maintaining the readiness of its distribution system when dual-fuel customers switch to natural gas on a critical day. Under the present regime, Bay State is obligated to operate its system in a way that would allow dual-fuel customers to switch to natural gas without notification. Consequently, the Company and its existing firm customers assume the costs associated with maintaining the system for such an occurrence. If dual-fuel customers do not use natural gas or only use the gas distribution system sporadically, then they probably do not fully contribute to the recovery of such costs. Based on the above, we find that Bay State's proposal is intended to ensure that the Company's distribution system is adequately prepared to

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183 The Company can only use its own gas, that is, gas it has procured to meet customer demand, in order to balance its system. In order to avoid the penalties detailed in the Company's Terms and Conditions, third-party suppliers will not deliver natural gas to an LDC's distribution system if their customers are scheduled to switch to an alternative fuel.

184 DOER's argument would be applicable only to those customers who actually purchase natural gas commodity from Bay State. If these customers, indeed, switched from natural gas to an alternative fuel on a critical day they could free up commodity resources to meet system needs. However, this is only theoretical; and the likelihood such behavior has not been supported on the record.

meet demand if and when dual-fuel customers switch to natural gas. We further find that the Company's proposal assigns costs to the dual-fuel customers appropriately.

Regarding the argument that the proposed provision will generate additional revenues for Bay State, the Department notes that, at present, the expected revenues from the Company's proposal are unknown at best. Bay State's distribution rates are designed to recover costs incurred for all customers. As dual-fuel customers switch to an alternative fuel (e.g., oil), Bay State will experience revenue erosion. The dual-fuel-related revenues that the Company will receive are intended to compensate Bay State for such erosion rather than result in increased revenues. Based on the above, we reject the Attorney General's argument that the revenues associated with the Dual-Fuel Provision are known and measurable and should be treated as such.

DOER's also argues that Bay State has not provided evidentiary support for the new charge. The Company's proposal, however, does not set a new charge. Rather, it provides some assurance that a dual-fuel customer, while paying the approved distribution rates, will use the system in way that does not burden Bay State's system or its firm customers with costs casued by, but not fully covered through charges due from, that dual-fuel customer.

Regarding AIM's argument that the proposed Dual-Fuel Provision was developed without any survey or discussion with customers, the Department notes that such a practice can be useful and productive for an LDC in providing quality service to its customers. However, the Department does not find that consultation with potentially affected customer groups is a prerequisite to a company's proposing a rate modification to the Department. In this case, we do not find that Bay State's failure to discuss with its customers its proposed Dual-Fuel

Provision is grounds for rejecting it. The logic of Bay State's proposal is sound enough to stand on its own. Finally, having found that Bay State's proposal is essential in ensuring the recovery of costs associated with system reliability and integrity, the Department approves the Company's Dual-Fuel Provision.

IX. BAY STATE GAS PBR PROPOSAL

A. Introduction

Bay State proposes a PBR plan as an alternative to traditional cost-of-service regulation (Exh. BSG/LRK-1, at 3). See, e.g., Boston Gas Company, D.T.E. 03-40, at 436-508 (2003); Incentive Ratemaking, D.P.U. 94-158 (1995). The components of the Company's proposed PBR plan are similar to the components of the PBR plan approved for Boston Gas Company in D.T.E. 03-40 (Exh. BSG/LRK-1, at 3-7). The primary component is a price-cap[185] formula that would apply to the Company's distribution service rates (id. at 3). Under Bay State's proposal, the Department would first establish distribution rates for the Company in the present proceeding based on cost-of-service ratemaking principles (Exh. DTE 4-45). The approved cast-off rates would then be adjusted annually consistent with the price-cap formula (Exhs. BSG/JAF-2, Sch. JAF-2-8; DTE 4-46).

The Company proposes that the PBR plan be implemented for a term of five years, from November 1, 2005, through October 31, 2010 (Exhs. BSG/LRK-1, at 7; DTE 4-45).

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[185] A price-cap is one form of a PBR plan. It is a plan with a price ceiling, or a pre-set price (generally set by a regulatory agency) that cannot be exceeded by the company operating under the price-cap plan (except for certain predetermined reasons). See, e.g., D.T.E. 03-40, at 436-446); D.T.E. 01-56, at 7-29; D.P.U. 96-50 (Phase I) at 259-260.

For each year that the PBR plan is in effect, the Company would submit a compliance filing to the Department for the implementation of new rates on November 1st of that year (Exh. DTE 4-45). According to Bay State, the last rate adjustment would take effect on November 1, 2009 (id.). Bay State proposes to continue the PBR plan beyond 2010 on a year-to-year basis after the initial five-year term "until such time it believes it can no longer achieve the intended efficiencies of the PBR plan that allow for optimal customer service, operational flexibility and reasonable Company earnings" (Exh. DTE 4-47). The Company would notify the Department of its intention to discontinue the PBR plan by filing an "intent to file for a general rate increase" with the Department (Exh. DTE 4-48). Bay State's proposed PBR plan is described below in the following parts: (1) the components of the proposed price-cap formula - the inflation index, the productivity offset, and the exogenous cost factor; and (2) implementation aspects of the plan - the term of the PBR plan, the earnings sharing mechanism, rate design flexibility, and the service quality index.

B. The Price-Cap Formula

1. Bay State Proposal

a. Introduction

Under Bay State's proposal, the percentage change in the Company's price-cap index ("PCI") is defined by the following formula:[186]

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[186] The term (PCI_t/PCI_{t-1} - 1) is the percentage change in the Company's price between year (t-1) and year (t). The term (P_t/P_{t-1} - 1) is the percentage change in the Gross Domestic Producer Price Index ("GDP-PI") between year (t-1) and year (t). The GDP-PI is a measure of the United States economy-wide inflation in the prices of final goods and services produced by the economy. Year (t) refers to the current year;

(continued…)

$$\left({PCI_t}/{PCI_{t-1}} \right) - 1 = \left({P_t}/{P_{t-1}} - 1 \right) - X + Z_t$$

where P_t is an inflation factor ("GDP-PI") in year t, X is the productivity offset (or the X-factor) and Z_t is the exogenous cost factor (or the Z-factor) which recovers the expense of certain exogenous factors that affect the Company's unit cost but are not accounted for in the inflation, or the X-factors (Exh. BSG/LRK-1, at 3-4). This formula is similar to the price-cap formula that the Department approved for Boston Gas in D.T.E. 03-40 (Exhs. DTE 12-11; DTE 12-12). The productivity offset, X, has three components: (1) a productivity differential; (2) an input price differential; and (3) a consumer dividend (Exh. BSG/LRK-1, at 5-6).[187] Bay State proposes to comply with the index-based limitations on its prices in two ways: (1) the Company's index-based price change in each year will not exceed the growth in the PCI; and (2) in any given year, no rate component within a rate class will increase by more than the rate of inflation as measured by the GDP-PI, or the PCI, whichever is greater (id., at 16).

Bay State proposes to measure the overall change in the Company's prices that are subject to the price-cap plan by computing an average rate of price change using information on price changes in individual rate elements (id.). In each year, Bay State will weigh the inflation in each rate element by its share of the Company's total regulated revenue for that

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186 (…continued)
Year (t-1) refers to the prior year.

187 The productivity differential and the input price differential are also referred to sometimes as the productivity growth index and the input price growth index.

rate class in the previous year (id.). The Company will calculate the overall rate adjustment as a weighted average of the price changes for the individual rate elements (id.).

b. Price Inflation Index

The Company proposes to use the annual growth in the GDP-PI as measured by the United States Commerce Department as the price inflation index (P_t), in the price-cap formula (id., at 8). Bay State proposes to measure inflation as the percentage change in the average of the four quarterly measures of the GDP-PI, relative to the same average in the prior year, as of the second quarter of each year (id.).

c. Productivity Offset

Bay State proposes that the productivity offset (or X-factor) be calculated as follows:

$$X = [(TFP^{IND} - TFP^{US}) + (W^{US} - W^{IND})] + CD$$

where

TFP^{IND} represents the total factor productivity ("TFP") trend for the Northeast gas distribution industry during the years 1990-2001;

TFP^{US} represents the TFP trend for the United States economy during the years 1990-2001;

W^{US} is an input price trend for the United States economy during the years 1990-2001;

W^{IND} is an input price trend for the Northeast gas distribution industry during the years 1990-2001; and

CD is a consumer dividend factor.[188]

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[188] The consumer dividend factor, also known as a "stretch factor," serves as a "future"

(continued…)

(Exhs. BSG/LRK-1, at 4; DTE 4-28).[189]

Bay State proposes to calculate the TFP index[190] as the ratio of an output quantity index to an input quantity index (Exh. BSG/LRK-1, at 4). The term (TFP^{IND} - TFP^{US}) is a measure of the productivity differential between the Northeast gas distribution industry and the United States economy and (W^{US} - W^{IND}) is a measure of the input price differential between the United States economy and the Northeast gas distribution industry (id.).

Bay State proposes an X-factor of 0.41 percent in the Company's price-cap formula (id., at 8). The sum of the productivity and input price differentials components of the proposed X-factor is 0.11 percent (id.). This value is identical to the sum of the productivity and input price differentials that the Department approved for Boston Gas in D.T.E. 03-40 (id., at 9).[191] The consumer dividend component of the proposed X-factor is 0.3 percent (id., at 8).

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188 (…continued)
productivity factor because it is intended to account for expected future gains in productivity due to the move from cost-of-service regulation to performance-based regulation. D.P.U. 96-50 (Phase I) at 280.

189 See, also, D.T.E. 03-40, at 477.

190 The TFP is used to measure the efficiency with which firms convert production inputs to outputs. It is defined as output per unit of total factor input.

191 The productivity study which Boston Gas performed in D.T.E. 03-40 measured the trends in productivity and input price growth of a sample of 16 LDCs located in the Northeast ("regional LDCs") and the United States economy during the years 1990 through 2001. The 16 LDCs together served approximately 60 percent of all gas end users in the Northeast (Exh. BSG/LRK-1, at 9); See, also, D.T.E. 03-40, at 476, n.241.

The Company submitted a study entitled, "O&M Cost Analysis for Bay State Gas Company" ("cost study") in support of its proposed price-cap formula (Exh. BSG/LRK-2, at 1).[192] The cost study is comprised of two parts: (1) an O&M econometric benchmarking study ("benchmark study"); and (2) an O&M cost trend analysis ("cost trend analysis") (id., at 3-29). The cost study defines gas distribution O&M cost to include the cost of gas delivery, customer accounts, and customer information services provided by LDCs (id., at 5).[193]

The benchmark study measures Bay State's O&M cost-efficiency from 1999 to 2003 (i.e., the Company's rate freeze period) using econometric cost modeling (id., at 5, 10). The benchmark study is based on a nationwide sample of distribution companies (id., at 10). The data for the study covered the period 1994 to 2003 (id., at 5, 10). The 43 gas distributors served approximately 53 percent of all gas end users in the United States (id., at 10). The study specifies a cost function which shows the relationship between the O&M costs of a utility and quantifiable business conditions in the utility's service territory (id., at 5). Bay State estimates the parameters of the cost model statistically using data on the historical costs of LDCs and the business conditions they faced (id.). The Company employs the estimated cost model to predict the average O&M cost of gas distribution services for Bay State given the business conditions that the Company faced (id.).

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192 The cost study was performed by the Pacific Economics Group ("PEG"), a consulting firm based in Madison, Wisconsin (Exh. BSG/LRK-2, at 2).

193 The O&M costs exclude the costs of gas procurement services, storage or transmission services, and pension because they are largely beyond management control and vary greatly among distributors (Exh. BSG/LRK-2, at 5, 7).

According to the Company, the benchmark study determined that: (1) the average O&M cost for Bay State was approximately 59 percent of the sample mean; (2) the number of customers served by Bay State was approximately 33 percent of the sample mean; (3) Bay State's throughput was approximately 34 percent of the sample mean; and (4) the Company's labor and materials costs were approximately eleven percent and one percent above their respective sample means (id., at 19-20). In addition, the benchmark study determined that Bay State's distribution main (in miles) was approximately 44 percent of the sample mean (id., at 20).[194] Furthermore, only 70 percent of the Company's distribution main was made of materials other than cast iron or bare steel, compared to 84 percent for the average U.S. gas distributor (id., at 20).

The benchmark study also determined that during the 1999-2003 rate freeze period, Bay State's average O&M cost was approximately 14.4 percent below its predicted value (id., at 6, 23-24). This result was statistically significant at the 95 percent confidence level (id.). The Company interpreted this result to mean that Bay State was "a significantly superior O&M cost performer" (id., at 6, 23).

The cost trend analysis compared Bay State's change in O&M costs in the five years before the Company's rate freeze took effect (i.e., 1993-1998) with the Company's O&M cost change in the five years while the rate freeze was in place (i.e., 1999-2003) (id., at 7).

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[194] According to the Company, this information, combined with the information on the number of customers, shows that Bay State had more distribution main per customer than the average US gas distributor (Exh. BSG/LRK-2, at 19). According to Bay State, this indicates that it served a more geographically dispersed customer base than the sample mean firm (id.).

According to the Company, the results of the cost trend analysis determined that, in inflation-adjusted terms, Bay State's O&M costs grew by 3.9 percent per annum, on average, over the 1993-1998 period (id.). In comparison, the Company's inflation-adjusted O&M costs declined by an average of 2.2 percent per annum over the 1999-2003 period (id.). The Company interpreted these results to mean that "Bay State's O&M cost trend therefore declined sharply while it was under the rate freeze compared with the O&M cost trajectory before the freeze took effect." (id.).

Based on the results of the benchmark study and the cost trend analysis, and on the Company's judgment as to the appropriate level of the consumer dividend for Bay State given recent Department precedent in D.T.E. 03-40, the Company proposed a consumer dividend factor of 0.3 percent (Exh. BSG/LRK-1, at 8-15). According to Bay State, the results of an identical cost trend analysis performed by Boston Gas in D.T.E. 03-40 showed that Boston Gas' O&M cost trend declined from 1.9 percent growth per annum to 0.6 percent per annum in real terms after Boston Gas' first PBR was implemented (i.e., a 1.3 percent per annum decline)[195] (id., at 12). In contrast, the magnitude of the difference between Bay State's O&M cost growth trends before and after the price freeze took effect is 6.1 percent per annum, which is more than four times greater than the comparable decline for Boston Gas (id., at 12-13).[196]

According to Bay State, the above results indicate that the Company has responded more strongly to the incentives created by its rate freeze than did Boston Gas to its first PBR

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[195] That is, [1.9 percent - 0.6 percent] = 1.3 percent (Exh. BSG/LRK-1, at 12-13).

[196] That is, [3.9 percent - (-2.2 percent)] = 6.1 percent (Exh. BSG/LRK-1, at 12-13).

plan (id., at 15). In addition, Bay State contends that the benchmark study shows that it is a "significantly superior O&M cost performer." (id.). Therefore, the Company "has fewer opportunities to achieve incremental productivity gains in the future" (id.). According to the Company, this implies that Bay State's consumer dividend should be no higher than the 0.3 percent consumer dividend factor approved for Boston Gas in D.T.E. 03-40 (id.).[197]

In summary, based on the results of the industry-wide productivity study which Boston Gas performed in D.T.E. 03-40, the results of the Company's benchmark study and cost trend analysis, and on the consumer dividend factor that the Department approved for Boston Gas in D.T.E. 03-40, Bay State has proposed a productivity offset, or X-factor, of 0.41 percent in the Company's price-cap formula (Exh. BSG/LRK-1, at 8). The value of the X-factor is the sum of the productivity and input price differential components of the productivity offset of 0.11 percent, plus a consumer dividend factor of 0.3 percent (id.). These values are identical to the values of the components of the X-factor that the Department approved for Boston Gas in D.T.E. 03-40 (id., at 9).

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[197] The Company stated that the Department precedent in D.T.E. 03-40 is relevant to Bay State because the Company, like Boston Gas, "is effectively updating a type of performance-based regulation plan." (Exh. BSG/LRK-1, at 11). According to the Company, Bay State has been subject to a rate freeze since 1999, and that a rate freeze "can be viewed as a type of GDP-PI - X plan, where the X-factor is implicitly equal to the growth rate in GDP-PI inflation each year." (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the Department should reject Bay State's proposed PBR plan because it does not cap prices and it does not create incentives to provide low-cost gas distribution service (Attorney General Brief at 30). The Attorney General states that the Department established its framework for a price-cap formula in Incentive Ratemaking, D.P.U. 94-158, and that the Department has applied that framework in successive cases (id.).[198] According to the Attorney General, Bay State's PBR plan differs significantly from the Department's established PBR precedent on several grounds (id. at 30-31). First, Bay State proposes that the Department reject the concept of reviewing all costs of distribution service when determining the relative efficiency of the Company (Attorney General Brief at 31). Second, Bay State denies customers the benefits of the first generation PBR consumer dividend of 0.5 percent to 1.0 percent while denying the benefits of the second generation PBR term of ten years (id. at 31). And third, Bay State proposes to remove the cost of capital addition from the PBR plan (id.).

According to the Attorney General, the Department allows a company to use the industry average productivity offset when the company can show that its cost is at or below that of the industry as adjusted for the particular characteristics of the company (id. at 32, citing D.P.U. 96-50 (Phase I) at 274-275 (1996)). The Attorney General claims that Bay State

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198 D.T.E. 03-40 (2003); D.T.E. 01-56, at 31 (2002); Boston Gas Company, D.P.U. 96-50-C (1997); D.P.U. 96-50 (Phase I) (1996); D.P.U. 94-50 (1995) (Attorney General Brief at 30-31).

fails to show that its cost is at or below the industry average, and in fact, Bay State's costs are above industry average (Attorney General Brief at 32). Therefore, the Attorney General contends that Bay State's cost history does not meet the Department's standard for establishing a PBR plan (id.).

In addition, the Attorney General contends that Bay State uses only its O&M costs and not the capital cost in the Company's cost analysis (id.). The Attorney General argues that this narrow analysis fails to provide a complete picture of the Company's costs and cannot be used to compare the Company's total productivity to that of the rest of the industry (id.). Therefore, the Attorney General contends that Bay State has not met the Department's requirements (id.).

The Attorney General claims that the Company's O&M expense productivity analysis fails to consider resources available to Bay State that further prove that the Company is less efficient than the industry average (id. at 33). The Attorney General argues that Bay State is part of a large corporation and of a combination of gas and electric companies, and thus Bay State is expected to have a lower unit distribution cost (id.).[199] Therefore, the Attorney General contends that Bay State's O&M expense productivity analysis overstates the expected cost and the Company's actual efficiency (id. at 33-34).

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[199] The Attorney General states that the Department approved NiSource's acquisition of Bay State based upon the expectations that the combined companies would bring improved productivity, economies of scale and lower costs to provide service (Attorney General Reply Brief at 10, citing Mergers and Acquisitions, D.P.U. 93-167-A at 4, 18 (1994), Eastern/Essex Acquisition, D.P.U. 98-27, at 26 (1998); NIPSCo/Bay State Acquisition, D.P.U. 98-31 (1998).

The Attorney General maintains that the Department should deny the Company's attempt to selectively use individual components from the Department's standard first and second generation PBR plans that benefit the Company the most (id. at 34). First, the Attorney General claims that Bay State proposes denying customers the benefit of the first generation PBR consumer dividend of 0.5 percent to 1.0 percent, while denying them the benefit of the second generation PBR term of ten years (id. at 31). The Attorney General argues that the Department found that a rate freeze as a result of a merger is not a PBR plan and, thus, Bay State's proposed PBR plan should be considered a first generation PBR plan (id. at 34-35). Accordingly, the Attorney General urges the Department to find, consistent with its precedent, that a consumer dividend of 0.5 percent to 1.0 percent is to be added to the X-factor of the Company's proposed PBR plan (id. at 35).[200]

The Attorney General further contends that Bay State's proposal to have a separate adjustment mechanism for its mains and services investment defeats the whole purpose of the price-cap formula and PBR plan (id.). According to the Attorney General, PBR plans provide incentives for companies to find the right mix of capital and labor that provides safe, reliable service at the lowest cost without constant Department oversight (id.). Further, the Attorney General contends that the Company's price-cap proposal will incorrectly increase the Company's base rates because the inflation rates, price indices, and productivity factor will be based on all costs, including capital costs (id. at 37).

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[200] The Attorney General states that if the Department finds that Bay State's proposed PBR plan is a second generation PBR plan, the Department, consistent with its precedent should reduce the consumer dividend (Attorney General Brief at 35 n.18).

Finally, the Attorney General disagrees with the Company's argument that the SIR will not defeat the purpose of the PBR Plan because the SIR focuses on public safety objectives that complement the PBR's efficiency objectives (Attorney General Reply Brief at 13). According to the Attorney General, the Company's argument does not address the method by which the Company identifies which capital additions are safety related (id.). Further, the Attorney General argues that Bay State's claim that the proposed Company's price-cap formula will prevent double recovery of steel replacement costs is incorrect (id. at 14). According to the Attorney General, the Company's proposed price-cap formula only removes from the price-cap increases in the incremental main, service, and meter investment made after the test year; and thus, the Company will recover twice for the replacement cost (id.). In sum, the Attorney General contends that the Department must reject the Company's proposal to extract capital cost out of the price-cap formula and deny the proposed creation of a new capital additions recovery mechanism (Attorney General Brief at 37).

b. DOER

DOER argues that the PBR plan proposed by Bay State fails to meet the Department's standard of review for PBR plans in the areas of economic efficiency, cost control, lower rates, and reduced administrative burden (DOER Brief at 3-4, citing D.P.U. 94-158, at 52-66; D.T.E. 03-40). DOER claims that the Company's proposed PBR plan is not comprehensive because its application is limited largely to "sunk" capital and O&M costs, leaving out a significant portion of the Company's future capital costs (DOER Brief at 4). In addition, DOER argues that Bay State's proposed PBR plan is different from Boston Gas' PBR plan, and

consequently, Bay State has no record support for its proposal based on the Boston Gas precedent (id.).

DOER contends that in D.T.E. 03-40, the Department established a PBR formula based on a performance study which included all of Boston Gas' costs, both capital and O&M costs (id.). DOER argues that Bay State's proposed PBR plan is based upon a study of the Company's O&M costs only, and therefore does not match the circumstances of the Boston Gas case (id. at 5). Thus, according to DOER, the components of Bay State's proposed PBR plan (consumer dividend, X-factor) should be different from Boston Gas' PBR plan (DOER Reply Brief at 3).

DOER states that the results of the Company's O&M cost study indicates that Bay State is a superior cost performer (DOER Brief at 5-6). DOER states that it analyzed the Company's capital cost data, and that the results from that analysis indicates that Bay State's average growth rate in capital spending was four times that of the industry average during the rate freeze period (id. at 5, citing Exh. DOER 1-6). Thus, DOER claims that Bay State is actually a little worse than an average cost performer (DOER Brief at 5, citing Tr. 17, at 2875). Furthermore, DOER claims that, based on its findings that Bay State's capital cost spending and the Company's own finding on the analysis of O&M costs, the evidence suggests that the Company has substituted capital for labor during the rate freeze period (DOER Brief at 6, citing Tr. 17, at 2872).

DOER disagrees with Bay State's claim that SIR costs are special and should be treated differently, and that a PBR applicable to sunk and non-SIR capital costs will be effective in managing cost and meet the Department's objectives (DOER Brief at 6). According to DOER,

the issue is not whether the costs are manageable, but whether the full benefits of the PBR formula are appropriate with these limitations on its applicability and in light of the infirmities of the total cost study (id. at 6, 7). Accordingly, DOER proposes a modification to the Company's PBR formula to reflect the limits of the costs covered by the PBR plan (id. at 7).[201]

DOER's proposed modification is based on an alternative PBR formula that will be applied to the Company's O&M costs only (id. at 7, citing Exh. DOER-1, at 7).[202] According to DOER, the proposed PBR modification is appropriate regardless of how the Department rules on the SIR adjustment (DOER Brief at 7).

In sum, DOER claims that the Company's PBR plan has not met the standard set for a PBR in prior cases, and that Bay State has attempted to distort that precedent to fit its circumstances (id. at 2). Therefore, DOER urges the Department to reject the proposed PBR unless modified as suggested (id. at 2).

c. AIM

AIM supports the PBR plan as an alternative to traditional cost of service regulation to deliver the most reliable and safe gas and electricity at the lowest and most reasonable cost to

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201 DOER argues that the alternative PBR formula must reflect the exclusion of the new capital cost (SIR and non-SIR), particularly because DOER's analysis suggests that the Company is not a superior performer in that cost area (DOER Brief at 7).

202 DOER recommends a partial application of the Company's proposal for the price-cap index to the portion of cast-off rates that relate to O&M costs (Exh. DOER-1, at 7). According to DOER, the use of this price-cap index would imply that the rest of the Company's costs are under a price freeze (id.). In addition, DOER argues that the PBR calculation would reduce the growth rate reflected in the PCI component of the formula by roughly a half (or 48.5 percent), which is the approximate portion of costs that are O&M costs (DOER Brief at 7).

all consumers (AIM Reply Brief at 1). AIM contends that the exclusion of certain costs from the PBR eliminates the incentives for cost containment and efficiencies that provide ratepayers benefits (id.). Therefore, the AIM requests that the Department carefully review the Company's proposed PBR plan, including the length and the exclusion of the SIR proposal, to insure that the PBR plan provides the appropriate incentives to maximize efficiencies and rate-payer benefits (id.).

d. Company

Bay State responds to its critics by stating that the Company has proposed a PBR plan that is consistent with sound economic principles and the Department's PBR standard (Bay State Brief at 158). Further, Bay State argues that the Company's proposed PBR plan is as consistent as possible with Boston Gas' PBR plan approved by the Department in D.T.E. 03-40 (id.). Bay State states that the Company has proposed the same productivity factor and consumer dividend that the Department approved for Boston Gas (id.). The Company maintains that the proposed PBR plan will create incentives for Bay State to continue to perform efficiently and to provide high quality service for its customers (id., citing Exh. BSG/LRK-1, at 2).

For example, Bay State argues that, contrary to the Attorney General's view, it is not Department policy to allow a company to use the industry average productivity offset only when the company can show that its cost is at or below that of the industry, as adjusted for the particular characteristics of the company (Bay State Brief at 184). Bay State contends that the reference in the Attorney General's brief does not support his view (id.). Further, Bay State claims that the Department has approved several comprehensive PBR plans using the industry

average productivity offset in cases where there was no econometric evidence on the companies' cost performance relative to the industry (id.).

Bay State contends that the Attorney General's position on the Company's total cost analysis is irrelevant because the capital costs used in these studies are characterized by the same capital vintaging concerns which the Department has found leads to distorted econometric results (id. at 184-185, citing D.T.E. 03-40, at 485). Moreover, Bay State argues that it has presented evidence demonstrating that both its capital and O&M cost performance improved during its rate freeze (Bay State Brief at 185, citing Exh. DTE 4-36).

According to the Company, the Attorney General's argument that Bay State's productivity analysis fails to recognize that Bay State is part of NiSource is incorrect (Bay State Brief at 185). Bay State argues that its econometric cost study estimates how efficient the Company's management is in controlling costs, given factors that are beyond the Company's control (Bay State Brief at 185). Bay State argues that the relationship between Bay State and NiSource is not a factor beyond the Company's control, and consequently the efficiencies from that relationship must be reflected in the econometric study (id.). Further, Bay State claims that the Company's efficiency calculation would have been incorrect had the Company controlled for Bay State's affiliation with NiSource (id., citing Exh. DTE 4-22). Therefore, Bay State contends that the Company's productivity analysis accurately assesses the Company's performance gains achieved since it became part of NiSource (Bay State Brief at 185).

Bay State argues that, contrary to the Attorney General's view, the Department has approved first generation PBR plans that contain both a five-year term and a consumer

dividend of less than 0.5 percent to 1.0 percent (id. at 186).[203] In addition, the Company contends that both the proposed consumer dividend and the proposed PBR plan term are based on Department precedent (id.). Bay State claims that its consumer dividend proposal is linked to the evidence reviewed by the Department in D.T.E. 03-40 for determining the consumer dividend (id.).[204] Further, the Company argues that a similar analysis presented in this case shows that Bay State has not more, but even fewer opportunities to achieve additional productivity gains than Boston Gas did (id.). Therefore, Bay State claims that the evidence shows that the Company's proposed consumer dividend is at the upper bound of a reasonable consumer dividend (id. at 186-187, citing Exh. DTE 4-27).

Bay State contends that the Attorney General and AIM's argument that the SIR proposal defeats the whole purpose of the PBR plan is incorrect for three reasons: First, Bay State argues that the SIR proposal focuses on public safety objectives that are complementary to, but distinct from, the efficiency gains that the PBR plan promotes, and thus it is appropriate to have separate adjustment mechanisms focusing on complementary aims (Bay State Reply Brief at 37-38; Bay State Brief at 187, citing Exh. DOER-1, at 6; Tr. 4, at 677-678). Second,

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203 The Company cites Blackstone Gas Company, D.T.E. 04-79 (2004), where the Department approved a PBR plan with a term of five years and an overall X-factor of 0.5 percent (Bay State Brief at 186). Bay State states that given the most recently approved net productivity growth and input price growth factor for Boston Gas was 0.11 percent, the approved consumer dividend for Blackstone Gas is accordingly 0.39 percent (id.).

204 The Company states that in D.T.E. 03-40, the Department approved a consumer dividend of 0.3 percent after assessing Boston Gas' performance in its expired PBR plan, and Boston Gas' potential for further productivity gains (Bay State Brief at 186, citing Exh. BSG/LRK-1, at 11).

Bay State claims that because the pattern and magnitude of the Company's SIR investment is unique, SIR investment costs are not reflected in the industry historical data which the Company used to develop the PBR formula (Bay State Reply Brief at 38; Bay State Brief at 188, citing Exh. BSG/Rebuttal-5, at 7; Tr. 4, at 678-679). And, third, Bay State states that the SIR is likely to promote efficiency and customer benefits compared with the alternative of not having it because the SIR will lead to savings in procurement and regulatory costs (Bay State Brief at 188, citing Exh. BSG/Rebuttal-5, at 7; Tr. 4, at 756-757,).

In addition, Bay State contends that the Attorney General is incorrect in arguing that Bay State's SIR proposal biases the inflation and productivity elements used in the price-cap index formula (Bay State Brief at 188). According to the Company, the SIR has been carefully designed[205] so that it does not lead to the double counting of steel replacement costs (id., citing Tr. 4, at 684). Further, Bay State claims that the Department has approved PBR plans with Z-factors, and that the presence of Z-factors does not bias the other elements of the price-cap formula (Bay State Brief at 189). Therefore, Bay State contends that because the SIR has been designed to be mathematically equivalent to a Z-factor, it also does not bias the productivity and inflation elements of the price-cap formula (id.).

Bay State disputes the Attorney General's argument that the Company will recover twice for the replacement costs because the Company's price-cap formula only removes from the price-cap increases in the incremental main service and meter investment made after the

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[205] According to Bay State, the SIR mechanism has been designed to be mathematically equivalent to a Z-factor, so that any rate adjustments resulting from the SIR are mathematically equivalent to the rate adjustments that would have occurred if those costs had been recovered instead through the Z-factor (Bay State Brief at 188-189).

test year (Bay State Reply Brief at 45, citing Attorney General Reply Brief at 14). Bay State argues that (1) only the extraordinary portion of replacement of bare and unprotected steel facilities would be recovered through the SIR, and (2) the price-cap formula applies only to the portion of Bay State's test year rates that excludes the accumulated costs of eligible steel replacement facilities (Bay State Reply Brief at 46, citing Exh. BSG/LRK-1, at 17). Accordingly, contrary to the Attorney General's claims, the Company contends that there is not double-counting of steel replacement costs because there is no overlap between the costs that are subject to the steel replacement mechanism and the costs that are subject to the PBR mechanism (Bay State Reply Brief at 46, citing Tr 4, at 684).

Bay State addresses a number of issues raised by DOER regarding the Company's PBR plan (Bay State Brief at 172-184). Bay State maintains that apparently DOER misunderstood the Department's precedent on PBR plans (id. at 178). The Company claims that DOER's belief that a comprehensive PBR plan can only be adopted for a company if there is a total cost study demonstrating "superior cost performance" for both capital and O&M costs is incorrect (id. at 177, citing DOER Brief at 4).[206] Bay State argues that the Department does not require a finding of "superior cost performance" for the capital and O&M costs before it approves a comprehensive PBR plan (Bay State Brief at 178).[207] Furthermore, Bay State argues that if

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[206] According to the Company, there have been a number of comprehensive PBR plans adopted by the Department without a total cost study (Bay State Brief at 177, citing D.P.U. 94-50; D.T.E. 01-56; D.T.E. 01-50 (2001); D.P.U. 96-50).

[207] Bay State argues that the Department approved a comprehensive PBR plan in D.T.E. 03-40 even though the Department found that Boston Gas was not a superior cost performer (Bay State Brief at 177).

those findings were necessary before a comprehensive PBR could be applied, the Department would not have approved any comprehensive PBR plans in Massachusetts (id.).

Regarding DOER's alternative PBR proposal, Bay State claims that the DOER proposal is inconsistent with any PBR plan approved by the Department, not well conceived, and contrary to the Department's objectives for effective incentive regulation (id. at 179). Bay State contends that DOER's proposed PBR plan recommends two different X-factors,[208] and argues that the Department has never approved a rate freeze and an index-based PBR plan applied to different set of costs in the same PBR formula (id.).

The Company argues that DOER's PBR proposal rests on the false premise that Bay State improved its O&M cost performance and not its capital cost performance during the rate freeze period (id. at 179-180). According to the Company, Bay State's capital input quantity index grew by 3.04 percent per year during the pre-freeze period, compared with 1.21 percent growth per year during the rate freeze period (id. at 180, citing RR-DTE-162). The Company claims that Bay State realized a 60 percent deceleration in the growth of its capital inputs while under the rate freeze, and that this capital cost improvement is comparable to the O&M cost trend cited favorably by the Department in D.T.E. 03-40 and used to support a 0.3 percent consumer dividend (Bay State Brief at 180). Therefore, Bay State argues that this evidence contradicts DOER's rationale for two X-factors (id.).

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[208] According to Bay State, DOER's proposal means that separate X-factors would be applied to O&M costs and capital costs, if capital costs are placed under a rate freeze (Bay State Brief at 179).

Bay State also characterizes DOER's recommendation of applying the PBR formula only to O&M costs as arbitrary (id.). Bay State claims that DOER does not provide any theoretical foundation or empirical evidence to support its recommendation (id., citing RR-DTE-162 (Rev. at 4). Further, the Company contends that having two X-factors in the same PBR plan will distort the Company's incentive to pursue cost efficiencies (Bay State Brief at 180).[209] According to the Company, that would be contrary to the Department's objectives to promote allocative efficiency (id. at 181, citing RR-DTE-162 (Rev. at 5)). In addition, Bay State claims that under the DOER's proposed PBR, the review of the PBR plan would also become much more cumbersome and costly, increasing regulatory costs and therefore, would be contrary to the Department's objectives for incentive regulation (Bay State Brief at 181).[210]

Bay State asserts that DOER's arguments that the Company's PBR cannot meet the requirements of the Boston Gas precedent are incorrect (id. at 183). The Company claims that it proposes not only the same PBR mechanism (except for the term) and the same price-cap formula as was approved in D.T.E. 03-40, but also offers the same types of evidence to determine an appropriate consumer dividend (id.).

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209 According to Bay State, a company under this type of plan would naturally consider how reductions in different sets of costs may impact its respective future X-factors, e.g., a company may decide to forego cost reductions in an area where costs have already been cut because doing so makes other areas look inefficient by comparison, thereby leading to a higher X-factor for those cost components in the future (Bay State Brief at 180-181, citing RR-DTE-162 (Rev. at 5)).

210 Bay State states that there would be incentives for parties to a proceeding concerning a PBR plan to identify relatively less efficient cost areas and propose higher X-factors for these areas (Bay State Brief at 181).

In sum, Bay State argues that DOER's proposal addresses a non-existing problem because Bay State improved both its O&M and capital cost performance during its rate freeze period (id.). Moreover, the Company contends that DOER misunderstands the Department's policy on PBR because there is no precedent or indication in the current proceeding supporting a restricted application of Bay State's PBR only to its O&M costs (id.). Therefore, Bay State asserts that DOER's proposal is unprecedented with respect to Massachusetts PBR plans, would unquestionably produce inferior performance incentives for the Company, and ultimately result in fewer benefits for Massachusetts customers (id. at 183-184). Bay State concludes that DOER's proposal is incompatible with the Department's objectives for incentive regulation and should be rejected (id. at 184).

3. Analysis and Findings

a. Introduction

Because PBR plans are alternatives to traditional cost of service regulation, they are subject to the same standard of review established by G.L. c. 164, § 94, which requires rates to be just and reasonable. D.P.U. 96-50 (Phase I) at 242, citing D.P.U. 94-158, at 52-66. A company seeking approval of an incentive proposal is required to demonstrate that its approach is more likely than traditional cost of service regulation to advance the Department's traditional goals of safe, reliable and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. D.P.U. 96-50 (Phase I) at 242-243.

Bay State's proposed price-cap PBR framework is consistent with Department precedent. D.P.U. 96-50 (Phase I) at 259-339; D.P.U. 94-158, at 52-66.[211] Further, the evidence examined below indicates that the Company's PBR proposal could benefit ratepayers (Exhs. BSG/LRK-2, at 7-9; DTE 4-33). Therefore, rather than flatly rejecting the Company's proposal as requested by the Attorney General, the Department examines the components of the proposal. In the remaining portions of this section, we analyze DOER's PBR proposal and the components of the Company's PBR proposal: the price-cap formula; term; earnings sharing mechanism; adjustments for exogenous costs; rate design and pricing flexibility; service quality; and the annual compliance filing.

b. DOER Alternative Price-Cap PBR Proposal

DOER states that there is little benefit in applying Bay State's price-cap formula to existing capital or "sunk" costs because most of the incremental efficiency gains achieved under PBR plans of the type proposed by Bay State result from O&M cost savings (Exh. DOER-1, at 4). Accordingly, DOER has proposed a partial application of Bay State's price-cap formula to the O&M portion of the Company's cast-off rates using the following formula.

$$PCI_t/PCI_{t-1} - 1 = 0.485((GDP\text{-}PI_t/GDP\text{-}PI_{t-1} - 1) - 0.41) + Z_t$$ [212]

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211 The components of the price-cap PBR plans may vary from company to company. See, e.g., D.P.U. 96-50 (Phase I) at 283 and D.T.E. 03-40 at 488.

212 According to DOER, the multiplier (0.485 or 48.5 percent) represents Bay State's O&M costs as a percentage of the Company's total costs (Exh. DOER-1, at 7).

(id., at 7). DOER proposes that the remaining portion of Bay State's costs, including capital costs, be placed under a rate freeze (id.).

The Department notes that DOER's proposal to apply the price-cap plan to Bay State's O&M costs only and place the rest of the Company's costs under a rate freeze will not serve the best interest of ratepayers for the following reasons. First, DOER's proposal would encourage the Company to "cherry-pick" regarding its investment and cost saving strategies in order to maximize revenues. For example, the Company may decide to postpone the replacement of its distribution mains if it determines that, by doing so, it can maximize revenues in the short to medium term, if capital investment costs are under a rate freeze, rather than under the price-cap plan. Second, implementing DOER's proposal is problematic because the multiplier (0.485 or 48.5 percent) for the partial price-cap formula that DOER has proposed could vary from year to year, unlike the productivity offset which remains constant throughout the term of the PBR plan. Therefore, the Department rejects DOER's alternative PBR proposal as inefficient and unduly complex. We now turn to reviewing the Company's price-cap formula.

c. Price-Cap Formula

The elements of the Company's proposed price-cap formula are the following: (1) an inflation index; and (2) a productivity offset, which consists of (a) a productivity differential, (b) an input price differential, (c) a consumer dividend, and (d) an exogenous cost factor. We now review these elements, individually.

i. Inflation Index

In D.P.U. 94-50, at 141, the Department concluded that the GDP-PI has the merits of being (1) the most accurate and relevant measure of the output price changes for the bundle of goods and services whose Total Factor Productivity ("TFP") growth is measured by the Bureau of Labor Statistics, (2) readily available, (3) more stable than other inflation measures, and (4) maintained on a timely basis. In subsequent proceedings, the Department approved the use of the GDP-PI as the inflation index in the price-cap plans approved for Boston Gas in D.T.E. 03-40 and D.P.U. 96-50 and The Berkshire Gas Company in D.T.E. 01-56. Those same merits obtain here. Therefore, consistent with Department precedent, we approve the use of the GDP-PI as the inflation index in the Company's price-cap formula.

In approving the Boston Gas PBR plan, the Department directed that the inflation index be calculated as the percentage change between the average for the prior year's four quarterly measures of the GDP-PI as of the second quarter of the year. D.T.E. 03-40 at 473. Therefore, consistent with Department precedent, we find that Bay State shall calculate its inflation index as the percentage change between the average for the current year's and prior year's four quarterly measures of the GDP-PI as of the second quarter of the year.

ii. Productivity Offset

(A). Introduction

The Company's proposed productivity offset consists of three components. These components are: (1) a productivity growth index, i.e., the average annual growth in productivity, during a specified time period, for regulated companies; (2) an input price growth index, i.e., the average annual growth in input prices, during a specified time period,

for regulated companies; and (3) a consumer dividend factor, i.e., expected future gains in productivity for a company that has moved away from cost-of-service ratemaking to performance-based ratemaking. See, e.g., D.P.U. 96-50 (Phase I) at 262-279.

(B). Productivity and Input Price Growth Indices

The productivity and input price growth indices taken together should determine the average annual increase in per-unit costs, during a specified period, for the regulated companies.[213] For a particular company, the indices serve as proxies for the growth in per-unit costs that the company should have experienced during the specified period, if it were an average-performing company. A company that achieved lower-than-average growth in per unit costs during this period would be rewarded under a price-cap regulation, i.e., it would have the opportunity to earn additional profits. Conversely, a company whose growth in per unit costs exceeded the average might realize lower-than-anticipated profits.

In the instant proceeding, the Department must decide whether the historic productivity and input price growth indices for Bay State should be based on regional or nationwide LDC indices. Next, the Department must decide whether the values of the productivity and input price growth indices proposed by Bay State are reasonable.

In D.P.U. 96-50 (Phase I) at 275-276, the Department found that the use of productivity growth indices for regional LDCs, i.e., Northeast LDCs, was appropriate for

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[213] For companies operating in a competitive market, the trend in per unit costs should be equal to the trend in output prices. Therefore, the difference between an industry's per unit costs and per unit costs of the United States economy should be equal to the difference between the industry's output prices and price inflation for the overall economy. D.P.U. 96-50 (Phase I) at 274, n.122.

Boston Gas. In its second generation PBR proceeding, Boston Gas presented additional evidence which supported the use of a regional definition of the gas industry in the Company's PBR proposal. D.T.E. 03-40, at 475. In that proceeding, the Department found that the use of the Northeast definition of the gas industry in the productivity study which Boston Gas performed in support of its PBR proposal was consistent with, and in fact, "improves upon what was found substantial and sufficient in our recent precedent." D.T.E. 03-40, at 475. Bay State has used the same productivity study performed by Boston Gas in D.T.E. 03-40 in support of the Company's PBR proposal in the instant proceeding. Therefore, consistent with our recent precedent, the Department finds that Bay State's use of a regional, i.e., Northeast, definition of the gas industry is appropriate. Similarly, the Department notes that the productivity growth index and the input price growth index proposed by Bay State are identical to those approved for Boston Gas in D.T.E. 03-40. Because these indices were calculated from an industry-wide productivity study which Boston Gas performed in D.T.E. 03-40, they are applicable to any gas distribution company in Massachusetts. Therefore, as we found in D.T.E. 03-40, the Department finds in the instant case that a productivity growth index and an input price growth index equal to negative 0.19 percent and 0.3 percent, respectively, are appropriate in the price-cap formula proposed by Bay State.

(C). Consumer Dividend

The Department stated its rationale for including a consumer dividend factor in the productivity offset of a price-cap formula in D.P.U. 94-50. The consumer dividend factor serves as a "future" productivity factor because it is intended to reflect expected future gains in productivity due to the move from cost-of-service regulation to performance-based regulation.

D.P.U. 94-50, at 165-166. In the instant proceeding, Bay State has proposed a 0.3 percent consumer dividend (Exh. BSG/LRK-1, at 10). Bay State has argued that the 0.3 percent consumer dividend is based on the results of the Company's benchmark study and cost trend analysis, and on the Company's judgement as to the appropriate level of the consumer dividend for Bay State given recent Department precedent in D.T.E. 03-40. Predicting the "expected future gains in productivity" for Bay State is difficult because of uncertainty about economic conditions in the future. As a starting point, in order to determine whether the consumer dividend proposed by Bay State is reasonable, the Department will evaluate the Company's performance under the rate freeze plan. Next, the Department will assess the evidence concerning the Company's potential for achieving additional productivity and efficiency gains during the term of the proposed PBR plan.

The evidence shows that Bay State's inflation-adjusted O&M expenses increased by 3.9 percent per annum, on average, during the period before the rate freeze, i.e., 1993-1998 (Exh. BSG/LRK-2, at 8). In comparison, Bay State's inflation-adjusted O&M expenses decreased by an average of 2.2 percent per annum during the rate freeze period, i.e., 1999-2003 (id.). In constant dollars, the Company's O&M expenses increased by an average of $2.86 million per year between 1993 and 1998, compared with a yearly decrease of $1.94 million between 1999 and 2003 (Exh. DTE 4-33). Therefore, the Company appeared to have achieved some efficiency gains in terms of slower O&M cost growth during the rate freeze compared to the period before the rate freeze took effect.

The Attorney General argues that the Department should reject the findings of Bay State's econometric benchmark study because the study overstates the Company's cost

savings during the rate freeze period. According to the Attorney General, because the econometric study treated Bay State as a stand-alone company, and not as part of a larger NiSource corporate system, the study failed to account for the resources which Bay State shares with NiSource and its subsidiary companies, which could lower the Company's unit distribution costs. The Department observes that because the efficiencies that Bay State achieved as a result of the NiSource merger were reflected in the post-merger cost data which the Company used for the econometric benchmark study, the Company has taken into account its affiliation with NiSource in the conduct of the econometric benchmark study.

The evidence shows that Bay State achieved a modest productivity gain during the rate freeze compared with the period before the rate freeze (Exh. DTE 4-36, at 3). The Company's TFP grew at an average annual growth rate of 1.29 percent during the rate freeze period, compared with an average annual growth rate of negative 0.05 percent during the period before the rate freeze (id.). The evidence further shows that the improvements in the Company's TFP growth rate during the rate freeze period were due primarily to the slower growth in labor and other O&M inputs (id., at 1). Bay State's labor input grew at an average annual growth rate of negative 5.94 percent during the rate freeze period, compared with a negative 0.41 percent average annual growth rate during the period before the rate freeze (id.). Other O&M inputs grew at an average annual growth rate of 0.55 percent during the rate freeze period, compared with an average annual growth rate of 11.3 percent during the period before the rate freeze (id.). Capital inputs also grew less rapidly in the rate freeze period (1.21 percent per year) compared with the period before the rate freeze (3.04 percent per year) (id.).

The Company claims that, compared with Boston Gas during its first PBR plan, Bay State is a significantly superior cost performer so that its consumer dividend should be no higher than the 0.3 percent consumer dividend approved for Boston Gas in D.T.E. 03-40. The claimed superior cost performance of Bay State compared with Boston Gas is misleading. Based on the cost trend analysis alone, Bay State appears to be a superior cost performer compared with Boston Gas during its first PBR plan. The magnitude of the difference between Bay State's O&M cost growth trends before and after the rate freeze is a decline of 6.1 percent per annum, which is more than four times greater than the comparable decline for Boston Gas (i.e., 1.3 percent per annum). However, because (1) the cost trend analysis was limited to O&M costs only, and did not control for the business condition variables[214] which each company faced, and (2) Boston Gas, compared to Bay State, was a stand-alone company during the period of its first PBR, the results of the cost trend analysis alone would not allow an accurate comparison of the total cost performance of the two companies. To perform this examination, the Department will need to compare the results of nearly identically-designed econometric cost studies for Bay State and Boston Gas which include total gas distribution costs as the dependent, and control for the business conditions variables which each company faced. We now examine the evidence regarding the cost performance of Bay State and Boston Gas based on the results of the econometric benchmark studies for the two companies.

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[214] Examples of business condition variables include the number of retail customers served by each company, input prices, the percentage of distribution main made of cast iron or bare steel, and the total miles of distribution main for each company (Exh. BSG/LRK-2, at 16-19).

The Department notes that the econometric benchmark studies for Bay State and Boston Gas differ in significant ways. First, Boston Gas defined gas distribution costs to include total gas distribution costs (capital and O&M costs) (Exh. DTE 4-1). In contrast, Bay State defined gas distribution costs to include O&M costs only (id.).[215] Second, the measure of "gas distribution O&M" included pensions and transmission and storage O&M expenses in the Boston Gas study (id.). These expenses were eliminated in the computation of O&M costs for Bay State (id.).[216] Third, the labor price in the Bay State study excluded pensions and benefit costs (id.). These costs were included in the Boston Gas study in D.T.E. 03-40 (id.). Fourth, the Bay State study included two additional independent or explanatory variables in the regression model: total miles of distribution main and a system age proxy variable[217] (id.). Finally, the Bay State study "used the percentage of non cast-iron and bare steel main in total

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215 The Company stated that it used O&M costs, instead of total gas distribution costs, in order to address the issues raised by the Department in D.T.E. 03-40 concerning capital 'vintaging' or the need to control for differences in the vintage (or the age) of capital additions reflected in the capital stock measure. According to Bay State, "the only way to control perfectly for differences in plant age is to know the entire pattern of capital additions that is manifested in the benchmark capital stock for each sampled distributor. [Because this did not prove feasible], the only way to ensure that the Department's concerns with capital 'vintaging' would be satisfied was to eliminate capital costs from the measure of gas distribution cost being benchmarked." (Exh. DTE 4-2).

216 The Company stated that pension costs were eliminated from O&M expenses in the Bay State econometric study because they are volatile, largely beyond the control of utility managers, and not subject to the PBR mechanism (Exh. DTE 15-19). Also, transmission and storage expenses were eliminated from O&M expenses in the Bay State econometric study in order to separate distribution labor and O&M expenses from non-distribution labor and O&M expenses (id.).

217 The Company defined the system age proxy variable as the number of gas distribution customers added in the last ten years divided by the total number of gas distribution customers (Exh. DTE 4-1).

main rather than the percentage of non cast-iron main, and eliminated the Boston Gas PBR dummy"[218] in the regression model (id.).[219] Because the econometric benchmark studies for Boston Gas and Bay State differ in significant ways, the Department cannot rely on the results of the Boston Gas' study to make a determination on Bay State's claim that the Company is a superior cost performer compared to Boston Gas during its first PBR Plan. The Department will determine the reasonableness of the 0.3 percent consumer dividend proposed by Bay State solely on the basis of Bay State-specific evidence.

Bay State updated its O&M econometric benchmark study to include the Company's total gas distribution costs, a system age proxy variable,[220] and a rate freeze dummy variable.[221] The results of the study showed that Bay State's (actual) total gas distribution cost was approximately 1.8 percent above the predictive value of the Company's distribution cost (i.e., $195.1 million (actual) compared with $191.5 million (predicted)) (Exh. DTE 4-10,

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218 The Boston Gas study included a PBR dummy variable in the regression model to estimate the independent effect of Boston Gas' first PBR plan on the Company's total costs (Exh. AG 13-2, Att. AG-13-2(b) at 17).

219 Bay State stated that the differences between the two studies were motivated by two objectives: (1) the need to improve the accuracy and/or efficiency of the econometric estimates since the Boston Gas study; and (2) to address the concerns raised by the Department in D.T.E. 03-40 concerning the capital 'vintaging' (Exh. DTE 4-1).

220 The Department notes that although the system age proxy variable did not completely address the Department's concerns regarding capital 'vintaging' in D.T.E. 03-40, its inclusion in Bay State's econometric benchmark study alongside the Northeast dummy variable is an improvement over the Boston Gas econometric cost study.

221 The Company included a rate freeze dummy variable in the econometric cost model to estimate the independent effect of Bay State's rate freeze on the Company's total costs (Exh. DTE 4-10, Supp.).

Supp.). The result was not statistically significant.[222] The result also indicated that the independent effect of Bay State's rate freeze on the Company's total gas distribution cost was not statistically significant. The coefficient of the rate freeze dummy variable was close to zero. Therefore, based on the results of the updated econometric benchmark study, the Department finds that Bay State is an average cost performer compared with the other gas distribution companies in the sample. We reject the Company's claim of being a superior cost performer.

The Attorney General recommends that, consistent with Department precedent, the Department should approve a consumer dividend of 0.5 percent to 1.0 percent for Bay State (Attorney General Brief at 35). According to the Attorney General, the 0.3 percent consumer dividend proposed by Bay State "denies customers the benefits of the first generation PBR [consumer] dividend of 0.5 percent to 1.0 percent" (id. at 31).

In summary, the Company's cost trend analysis and productivity study indicate that Bay State reduced its O&M cost growth, and achieved modest productivity gains during the rate freeze period compared to the period before the rate freeze took effect (Exhs. BSG/LRK-2, at 8; DTE 4-36). However, the results of the updated econometric benchmark study shows that Bay State is not a superior cost performer, but an average cost performer compared with other distribution companies in the sample, contrary to the Company's claim (Exh. DTE 4-10 (Supp.)). This result indicates that Bay State has the

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222 The t-statistic was used to test the null hypothesis of whether the difference between the Company's actual total cost and the predicted total cost equals zero. The results of the test indicated a t-statistic of 0.58. As the t-statistics is less that 2 in magnitude, the Company fails to reject the null hypothesis.

potential to achieve further efficiency gains going forward. The Company's witness testified that most of the restructuring activities undertaken during Bay State's merger with NiSource Corporation and the follow-on merger with Columbia Energy Group will continue to generate cost savings and organizational efficiencies for Bay State during the term of the PBR (Exh. BSG/SHB-1, at 21-23). In addition, the Company's continued participation in the system-wide cash management and pooled borrowing programs for all NiSource subsidiaries will generate significant savings in financing costs for Bay State during the term of the PBR plan (Exh. BSG/SHB-1, at 21-23).

In conclusion, based on our analysis of the Company's cost and productivity performance, and our assessment of the potential for Bay State to achieve significant cost savings and efficiency gains going forward, the Department rejects the Company's claim that Bay State is a superior cost performer with little potential to achieve significant cost savings going forward. Instead, we find that Bay State is an average cost performer compared with the distribution companies in the sample, and that the Company has the potential to achieve significant cost savings and efficiency gains during the term of the PBR plan. Therefore, we reject the 0.3 percent consumer dividend factor proposed by Bay State. The Department finds that a consumer dividend factor equal to 0.4 percent[223] in the price-cap formula is reasonable and warranted in the instant proceeding.

(D). Summary of Productivity Offset

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[223] The Company's PBR witness testified that a consumer dividend factor between 0.0 percent and 0.5 percent is reasonable for Bay State (Tr. 4, at 758-759).

Based on the findings stated above, the Department directs the Company to recalculate the productivity offset in the price-cap formula in the following manner. First, the Company is directed to use a value of 0.3 percent for the input price growth index. Second, the Company shall use a value of negative 0.19 percent for the productivity growth index. Third, the Company is directed to include a consumer dividend factor equal to 0.4 percent. This results in an overall productivity offset equal to 0.51 percent. The productivity offset shall remain constant throughout the term of the PBR plan.

iii. Exogenous Cost

(A). Introduction

Bay State proposes to recover (or return) exogenous (or Z-factor) costs that are not reflected in the inflation and productivity differential components of the X-factor (Exh. BSG/LRK-1, at 15). The Company has defined exogenous costs to include, but be not limited to, the following: (1) changes in tax laws, accounting principles, and regulatory, judicial, or legislative actions uniquely affecting the local gas distribution industry; and (2) cost changes that are beyond the Company's control and not accounted for in the GDP-PI term used in the Company's PBR plan (id.). According to Bay State, the proposed Z factor is consistent with the Department's precedent and its definition of exogenous costs (id., at 16). Under the Company's proposal, individual exogenous costs will have to exceed a $600,000 threshold in a particular calendar year in order for the Company to request recovery (id., at 15; BSG/JAF-2, at 29).[224] In its brief, Bay State reiterated the importance of having an exogenous cost and

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[224] Bay State determined the threshold for the recovery of exogenous costs by multiplying (continued…)

reiterated the threshold of $600,000 (Bay State Brief at 166, citing Exhs. BSG/JAF-1, at 28, BSG/JAF-2, at 29). No other party commented on this issue.

(B) Analysis and Findings

The Department has now reviewed definitions of exogenous costs in several ratemaking contexts. D.P.U. 96-50 (Phase I) at 292; D.T.E. 98-31, at 17; D.T.E. 98-27, at 19; D.T.E. 98-128, at 54-55; D.T.E. 01-56, at 25; D.T.E. 03-40, at 488-492. The 1998 and later cases follow D.P.U. 96-50's definition of exogenous costs. Exogenous costs are defined as follows:

> [E]xogenous costs shall be defined as positive or negative cost changes actually beyond the Company's control and not reflected in the GDP-PI, including but not limited to cost changes resulting from:
> - changes in tax laws that uniquely affect the local gas distribution industry;
> - accounting changes unique to the local gas distribution industry; and
> - regulatory, judicial, or legislative changes uniquely affecting the local gas distribution industry.

D.P.U. 96-50 (Phase I) at 292.

Proponents of exogenous cost recovery will bear the burden of demonstrating that the cost was (1) beyond the company's cost control, and (2) not reflected in the GDP-PI. We note that Bay State's proposed definition of exogenous costs is the same as that approved for Boston Gas in D.T.E. 03-40, at 488-492 and D.P.U. 96-50 (Phase I), at 292 (Exh. BSG/LRK-1, at 15). Therefore, the Department accepts the Company's definition.

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[224] (…continued)
the Company's 2004 test year operating revenues of $481,909,253 by a factor of 0.001253, which the Department established in D.T.E. 98-128 and D.T.E. 01-56, and approved recently for Boston Gas in D.T.E. 03-40 (Exhs. BSG/LRK-1, at 15; BSG/JAF-2, at 29).

Bay State has proposed an exogenous cost threshold of $600,000 in the instant proceeding. In D.P.U. 98-128, at 53-56 and D.T.E. 01-56, at 22-26, the Department established the method by which the threshold level for recovery of exogenous costs must be set. We determined that the exogenous cost threshold must be the result of multiplying a company's operating revenues by a factor of 0.001253.[225] Applying this ratio to Bay State's operating revenues of $481,909,253 results in an amount slightly over $600,000 (Exhs. BSG/JAF-1, Sch. JAF-1-1 at 2; BSG/JAF-2, at 29).[226] We find that this is a reasonable amount for a company with operating revenues of $481,909,253 that is implementing a multi-year PBR plan. Accordingly, we set the threshold for exogenous cost recovery for the term of the PBR plan at $600,000 for each individual event in the preceding calendar year.

C. Term of the Plan

1. Bay State Proposal

The Company proposes to establish the PBR plan on November 1, 2005, coincident with the effective date of the cast-off rates resulting from the rate case (Exh. DTE 4-45). The proposed term of the Company's PBR plan is five years effective November 1, 2005 through October 31, 2010 (Exhs. BSG/LRK-1, at 7; DTE 4-45). According to Bay State, the five-year term balances the need to have a PBR plan that is "long enough to create meaningful performance incentives for the Company", but "short enough so that the index-based price

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[225] This factor is the ratio of Colonial Gas Company's exogenous cost threshold to its operating revenues. D.T.E. 98-128, at 53-56; D.T.E. 01-56, at 22-26.

[226] The exact amount is $603,832 (i.e., $481,909,253 x.001253 = $603,832.29).

changes reflect recent TFP and input price trends" (Exh. BSG/LRK-1, at 7). The Company would file five annual compliance filings establishing rates to take effect on November 1st of each year (Exh. DTE 12-1). The first PBR rate adjustment would take place on November 1, 2006 and the last PBR rate adjustment would take place on November 1, 2009 and will be effective through October 31, 2010 (Exh. DTE-4-45).

Bay State proposes to continue the PBR plan on a year-to-year basis after the initial five-year term "until such time as it believes it can no longer achieve the intended efficiencies of the Plan that allow for optimal customer service, operational flexibility and reasonable Company earnings." (Exh. DTE 4-47). The Company will notify the Department of its intention to discontinue the PBR plan by filing an "intent to file for a general rate increase" with the Department within thirty days of the Company's general rate case filing (Exh. DTE 4-48).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should deny the Company's plan to selectively use individual components from the Department's standard first and second generation PBR plan that benefit the Company the most (Attorney General Brief at 34). The Attorney General argues that the Department found that a rate freeze as a result of a merger is not a PBR plan and, Bay State's proposed PBR plan should be considered a first generation

PBR plan (id. at 34-35). Therefore, the Attorney General concludes that the Department should approve a term of the PBR plan of five years (Attorney General Brief at 35).[227]

No other party commented on the term of the PBR plan.

b. Company

Bay State contends that it selected a five- year PBR plan because it is more consistent with Department PBR precedent (Bay State Brief at 186, 187, citing Tr. 4, at 687-688). The Company argues that it proposes a rate indexing for the first time, similar to Blackstone Gas in D.T.E. 04-79 and Boston Gas in D.P.U. 96-50 and that the precedents set in those plans support a term of five years (id. at 187, citing Exh. BSG/LRK-1, at 7). Further, the Company claims that it comes off a five-year rate freeze, and if it proposed an indexing term of five years it would be consistent with the Berkshire Gas precedent, where the rate freeze and indexing terms also summed to ten years (Bay State Brief at 187).

3. Analysis and Findings

The Department has stated that one potential benefit of incentive regulation is a reduction in regulatory and administrative costs. D.P.U. 94-158, at 64; D.P.U. 01-56, at 10. Additionally, the Department has found that a well-designed PBR plan should be of sufficient duration to give the plan enough time to achieve its goal and to provide utilities with the appropriate economic incentives and certainty to follow through with medium and long-term

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[227] The Attorney General states that if the Department finds that Bay State's proposed PBR plan is a second generation PBR plan, the Department should consistently follow its precedent and order a ten-year PBR plan (Attorney General Brief at 35 n.18).

strategic business decisions. D.P.U. 94-158, at 66; D.P.U. 96-50 (Phase I) at 320; D.T.E. 01-56, at 10.

Bay State argues that because the Company is proposing a rate indexing PBR plan for the first time, the term of the plan should be five years, consistent with Department precedent (Exh. DTE 4-40). Further, the Company contends that because it has come off a five-year rate freeze, a term of five years for the PBR plan is appropriate to bring the total number of years that the Company has been under a performance-based ratemaking plan to ten, which is consistent with the Berkshire Gas precedent (Bay State Brief at 187).

The Department approved a term of five years for the initial rate indexing PBR plan for Boston Gas in D.P.U. 96-50 (Phase I), and a ten-year term for Boston Gas' second generation PBR plan in D.T.E. 03-40. The Department approved a term of ten years for the combined rate-freeze and rate indexing PBR plan for Berkshire Gas in D.T.E. 01-56. The Department has considered the merits of ten-year PBR plans versus five-year PBR plans, and notes that ten-year PBR plans have certain advantages over five-year PBR plans in terms of creating an environment that allows medium and long-term efficiency planning and business decision making (Exh. DTE 4-40). In addition, ten-year PBR plans provide stronger incentives for companies to achieve efficiency gains and significant cost savings through innovation, deployment of productivity-enhancing technology, and other measures (id.). Therefore, the Department concludes that the five-year term proposed by Bay State is not long enough to achieve the efficiencies and benefits that a PBR plan is expected to provide to shareholders and ratepayers. Accordingly, we reject the five-year term (with "evergreen"

renewal)[228] proposed by Bay State. Rather, the Department considers a term of ten years as reasonable for Bay State to implement long-term business strategies that could produce significant cost savings and other benefits to ratepayers and shareholders. Finally, a ten-year PBR plan will reduce the regulatory burden of implementation.

Bay State argues that a longer-term PBR plan exposes the Company to greater market and other business risks because of the uncertainty about long-term economic conditions (id.). However, the exogenous cost factor and the earnings sharing mechanism incorporated into the PBR plan will mitigate risks that shareholders and ratepayers may face as a result of a ten-year PBR plan.

In terms of Department precedent, when approving long-term PBR plans the Department has taken note of remedies available to Companies under such plans. These remedies have included a formal mid-period review (See D.T.E. 01-56 at 10-11; D.T.E. 03-40 at 497), and acknowledgment that companies retain the option to petition the Department for changes in tariffed rates in reaction to extraordinary economic conditions. D.T.E. 03-40, at 497 n.263.

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[228] In D.T.E. 03-40 and D.P.U. 96-50 (Phase I), the Department rejected similar proposals by Boston Gas to extend the initial five-year term of its PBR plan on a yearly basis because such one-year planning horizons "would prevent the Company from receiving the appropriate economic incentives and certainty to follow through with medium and long-term strategic business decisions." See D.T.E. 03-40, at 495.

The Department affords the Company both of these options in the instant case. In terms of the mid-period review, either the Company or the Department may initiate said review.[229]

D. Earnings Sharing Mechanism Deadband

1. Bay State Proposal

Under the earnings sharing mechanism ("ESM") proposed by Bay State, a deadband of 400 basis points would be established around the Company's authorized return on equity ("ROE") (Exh. BSG/LRK-1, at 17-18). There would be no earnings sharing if earnings were within the allowed ROE plus or minus 400 basis points (id.). If the Company's actual ROE were 400 basis points below the its authorized ROE, 75 percent of the loss would be borne by shareholders and 25 percent of the loss would be borne by ratepayers (id., at 18). If the Company's ROE exceeded its authorized ROE by 400 basis points, then 75 percent of the gain would accrue to shareholders and 25 percent to ratepayers (id.). According to Bay State, the Company's ESM is identical to the ESM approved for Boston Gas in D.T.E. 03-40 and D.P.U. 96-50 (Phase I) (id.).

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229 The mid-period review for the PBR is to be distinguished from any filing or proceeding the Company could initiate concerning its proposed SIR program as addressed in Section II.

2. Positions of the Parties

a. DOER

DOER opposes the Company's proposed ESM (DOER Brief at 13). According to DOER, the Company provides no other basis for its proposal other than that it is the same ESM as adopted by the Department for Boston Gas (id. at 9). Further, DOER claims that Bay State's proposed ESM does not provide the Company with adequate incentive to reduce costs sufficiently to provide any ratepayer benefits (id. at 13).[230] Thus, DOER claims that the Company's proposed ESM is more heavily tilted toward shareholders than any of the ESMs adopted by other jurisdictions surveyed by DOER (id. at 10, citing Exh. DOER-AEP-1).

DOER contends that an ESM should reflect the potential for savings, difficulties for achieving those savings and the risks to the Company in earning its allowed ROE (DOER Brief at 10). As an alternative to the Company's proposed ESM, DOER proposes that the Department consider a mechanism to provide the Company the opportunity to retain 100 percent of the increased revenues associated with the first 50 basis points earned above the allowed ROE (id. at 13). DOER argues that, thereafter, there should be a sharing of the next 51-200 basis points as follows: 75 percent ratepayers and 25 percent shareholders and 75 percent shareholders and 25 percent ratepayers for amounts above 200 basis points (id.). DOER claims that under its proposal, the shareholders would receive a greater percentage of earnings as efficiency gain increase (DOER Reply Brief at 5). Consequently, DOER contends

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230 DOER argues that the Company already has achieved significant savings from the effects of a rate freeze and that the Company should have more incentives to reach for greater, perhaps more difficult savings (DOER Brief at 10, 11).

that its ESM proposal meets the dual goals of creating efficiency gains and sharing of those with customers (id.).

DOER urges the Department to consider the likelihood of reaching cost savings and sharing those with customers, when evaluating an ESM proposal (DOER Brief at 11). DOER claims that even under the Company's revised 200 basis point spread,[231] customers would not receive any benefit until the Company cuts costs by $4.3 million[232] (id., citing Exh. DTE-DOER 1-9).

No other party commented on Bay State's proposed ESM.

b. Company

Bay State points out that it has proposed an ESM identical to the one approved for Boston Gas in D.T.E. 96-50 as well as in D.T.E. 03-40. (Bay State Brief at 167). The Company indicates that Bay State would accept a 200 basis point earnings sharing deadband, as well as a sharing outside of the band of 50 percent to shareholders and 50 percent to customers (id. at 168). Further, Bay State argues that an ESM should (1) allow customers to share in the benefits of efficiency gains under the PBR plan, and (2) provide a symmetrical mitigation of the risks, to both customers and shareholders (id.).

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231 DOER states that Bay State has proposed an alternate ESM which provides that the Company would retain all earnings that are up to 200 points above its allowed return on equity with a sharing ratio of 50/50 (DOER Brief at 10, citing Exh. BSG/Rebuttal-5, at 10).

232 According to DOER, that amount represents 25 percent of the proposed revenue increase in the present proceeding (DOER Brief at 11, citing Exh. DTE-DOER 1-9).

Bay State disagrees with DOER's argument that the Company's proposed ESM is tilted towards shareholders (id. at 176). Bay State claims that the PBR plan approved for Berkshire Gas has no earning sharing mechanism, and therefore does not require shareholders to share any earnings with customers (id. at 176-177, citing D.T.E. 01-56, at 7).

Bay State claims that DOER's proposal in which customers will receive 75 percent of all earnings within a band above the allowed ROE would create minimal incentives for the Company and discourage it from taking actions that could improve its efficiency (Bay State Brief at 176, citing DOER Brief at 10-11, Exh. BSG/LRK-1, at 17-18; Tr. 24, at 3990). Further, Bay State argues that under such ESM, a company would not pursue cost savings initiatives that require upfront cost in the early years but which reduce costs in later years (Bay State Brief at 176). According to Bay State, a Company will not pursue cost savings initiatives whenever the net present value ("NPV") is less than its upfront costs (Bay State Reply Brief at 41). Bay State argues that the NPV can be reduced both by reducing plan terms and by increasing the amount of savings that must be shared with customers (id. at 41-42). Therefore, Bay State argues that the sharing fractions proposed by DOER are not only high but punitive, and will tend to make a greater number of efficiency-enhancing initiatives unprofitable (id. at 42).

3. Analysis and Findings

In prior proceedings, the Department has recognized the issue of uncertainty associated with setting the productivity factor. See, e.g., D.T.E. 03-40, at 500. The Department has also recognized that earnings sharing could provide ratepayers a backstop to improper setting of the productivity factor. See, e.g., D.P.U. 96-50 (Phase I) at 325; D.P.U. 94-50, at 197.

Specifically, the Department has stated that protection through a mechanism such as an ESM is required for ratepayers. D.P.U. 96-50 (Phase I) at 325.

In the instant case, the considerations remain at the heart of the ESM question. The Department must provide ratepayers with a backstop to improper setting of the productivity factor. The Department has before it the following two proposals for an ESM: (1) DOER's proposed ESM; (2) the Company's ESM that is identical to that approved for Boston Gas in D.T.E. 03-40 and D.P.U. 96-50 (Phase I); and (3) the Company's revised 200 basis point spread ESM.

Turning first to DOER's proposal, DOER did not provide any substantial evidence to support its proposed ESM. Therefore, the Department cannot accept DOER's claim that the ESM proposed by Bay State "does not provide the Company with sufficient incentive to reduce costs sufficiently to provide any ratepayer benefits." For the same reason, the Department cannot accept DOER's claim that its proposed ESM "meets the dual goals of creating efficiency gains and sharing of those gains with customers." Therefore, we reject DOER's ESM proposal.

Turning to the ESM proposed by Bay State, as we stated in D.T.E. 03-40 and D.P.U. 96-50 (Phase I), the Department still finds that it is necessary to protect ratepayers with an ESM. We note that the ESM (1) includes a shareholder/ratepayer sharing ratio that provides Bay State with economic incentives, (2) includes a bandwidth that appropriately balances Company and ratepayer risks, and (3) is consistent with Department precedent. Therefore, we approve the Company's proposed ESM.

E. Pricing and Rate Design Flexibility

1. Introduction

Bay State proposes pricing and rate design flexibility under its price-cap plan identical to the pricing flexibility allowed Boston Gas in D.T.E. 03-40 and D.P.U. 96-50 (Phase I) (Exh. BSG/LRK-1, at 16-17). This flexibility would allow Bay State to allocate the price-cap increase or decrease within a rate class at its discretion, as long as no rate element within a rate class increases more rapidly than the rate of inflation as measured by GDP-PI or the price index increase, whichever is greater (id., at 16). In addition, the Company's index-based price change in each year will not exceed the growth in the PCI (i.e., GDP-PI inflation minus the X-factor plus or minus any Z-factor cost) in that year (id.). According to Bay State, the pricing flexibility will enable the Company to increase pricing efficiency (id., at 17). In its brief, Bay State reiterated the importance of having a measure of flexibility in pricing while insuring that no rate element can increase more rapidly than GDP-PI inflation or Price-Cap Index (Bay State Brief at 169, citing Exh. BSG/LRK-1, at 16). No other party commented on this issue.

2. Analysis and Findings

The Company's proposal to retain some discretion in allocating each rate class' price-cap change to the individual rate components within the class is identical to the rate design flexibility approved for Boston Gas in D.T.E. 03-40 and D.P.U. 96-50 (Phase I) and for Berkshire in D.T.E. 01-56. D.T.E. 03-40 at 502-504; D.P.U. 96-50 (Phase I) at 333-334; D.T.E. 01-56, at 26-27. No party opposed the Company's proposed rate design flexibility.

The Department agrees with the Company that it should retain some discretion in allocating the price-cap increase or decrease between rate elements within a class, as long as no

rate component increases by more than the rate of inflation. Allowing Bay State to set the rate component changes within a class should help the Company to achieve pricing efficiency, and to reduce intra-class subsidies and high bill impacts for individual customers. This flexibility gives the Company some intra-class rate discretion, while ensuring that each individual rate element cannot increase above the inflation rate for the duration of the PBR plan.

Therefore, consistent with Department precedent, we approve the rate design and pricing flexibility proposed by Bay State. D.T.E. 03-40, at 502-504; D.P.U. 96-50 (Phase I) at 333-334; D.T.E. 01-56, at 26-27. Should the price-cap increase be greater than the rate of inflation, because of the recovery of exogenous costs, the Department directs the Company to increase each rate component price at no more than the rate provided for in the price-cap formula.

F. Service Quality Plan

1. Introduction

Bay State did not include a service quality plan with its PBR proposal. Rather, the Company agreed that it remains subject to the Department's current service quality guidelines set forth in Service Quality Standards for Electric Distribution Companies and Local Gas Distribution Companies, D.T.E. 99-84 (2001) (Exh. BSG/LRK-1, at 18). In addition, Bay State agreed to comply with all changes and modifications the Department may make to the service quality guidelines set forth in D.T.E. 99-84 (Exh. DTE 4-52). No other party commented on the Company's service quality proposal.

2. Analysis and Findings

Along with other utilities in the Commonwealth, the Company is governed by the Service Quality Guidelines established by the Department in D.T.E. 99-84. The Company's Service Quality Report reveals that the Company met its service quality standards for all penalty measures during the 2004 service quality period (Exh. DTE-1).

The record reveals that the Company intends on complying with any new or revised Service Quality Guidelines that may be developed in Department's most recent service quality proceeding in D.T.E. 04-116, even if the Company's PBR term were to be longer than that proposed by the Company (Tr. 1, at 255-256). While the Company's agreement to comply with future changes in the Service Quality Guidelines during the PBR term would estop its arguing compliance in the future, our authority to direct compliance with guidelines established in D.T.E. 04-116 does not depend on the litigant's volunteered representation.

G. Compliance Filings

1. Introduction

The Company proposes that price changes under its price-cap formula would be based on a compliance filing establishing rates for effect on November 1st each year, starting on November 1, 2005 (Exh. DTE 4-45). The first rate adjustment in accordance with the PBR plan will become effective on November 1, 2006 (id.). The last rate adjustment would take effect on November 1, 2009 (id.). No party commented on the Company's proposal for the submission of annual compliance filings.

2. Analysis and Findings

In D.P.U. 96-50 (Phase I) at 338-339, the Department directed that each year Boston Gas must submit the following documentation supporting the base rate adjustments: (1) the

determination of normal billing determinants and revenues to determine the weighted average price to which the price-cap will be applied; (2) a calculation of the new price-cap, including documentation of the exogenous factors and capital cost changes; (3) development of new rates consistent with the annual price-cap calculation; and (4) class-by-class bill impacts, including gas costs, comparing the proposed rates to the then-current rates. Also, the Department found in D.P.U. 96-50 (Phase I) at 338-339, that Boston Gas' weighted average price for the previous year would be calculated using revenues and billing determinants normalized for weather. Lastly, the Department emphasized that "to the extent the Company submits the annual filings in a clear and comprehensive manner, with supporting data, this will facilitate the review of such filings by the Department and other parties." D.P.U. 96-50 (Phase I) at 339.

The Department directs Bay State to submit in its annual compliance filings the same supporting documentation that we required for Boston Gas in D.P.U. 96-50 (Phase I) and, as part of these filings, to submit its weighted average price for the previous year calculated using revenues and billing determinants normalized for weather. The Company is directed to submit its annual compliance filings each September 15th commencing in 2006 and continuing for the ten-year term of the PBR plan. Submission of annual plans is not optional or contingent on intent to continue the PBR plan from year to year after the initial five years. Subject to discussion at Section IX.C.3, above, the PBR plan shall continue in effect for a total of ten consecutive years starting November 1, 2006, with the last adjustment taking effect on November 1, 2015.

X. QUALITY OF SERVICE

A. Introduction

On November 25, 1997, the Restructuring Act was enacted, authorizing, among other things, the Department to promulgate rules and regulations to establish PBR rates for each utility company. G.L. c. 164, § 1E ("Section 1E"). Section 1E directs the Department to establish minimum standards of service quality ("SQ") for companies operating under PBR plans. Id. Section 1E(b) further provides:

> In complying with the service quality standards and employee benchmarks established pursuant to this section, a distribution, transmission, or gas company that makes a performance based rating filing after the effective date of this act shall not be allowed to engage in labor displacement or reductions below staffing levels in existence on November 1, 1997, unless such are part of a collective bargaining agreement or agreements between such company and the applicable organization or organizations representing such workers, or with the approval of the [D]epartment following an evidentiary hearing at which the burden shall be upon the company to demonstrate that such staffing reductions shall not adversely disrupt service quality standards as established by the [D]epartment herein. also requires that no labor displacement or reductions below staffing levels in existence on November 1, 1997, may take place unless they are part of a collective bargaining agreement or otherwise approved by the Department.

Accordingly, on June 21, 2002, the Department issued SQ Guidelines to fulfill the directives of Section 1E. Service Quality Standards for Electric Distribution Companies and Local Gas Distribution Companies, D.T.E. 99-84 (2001). Regarding staffing levels, the Guidelines provided the following:

> Staffing benchmarks will be established on a company-specific basis and will be determined by the then effective collective bargaining agreement for each Company.

D.T.E. 99-84, Att. 1, § IV.

On May 28, 2002, the Department approved an SQ plan based on the Guidelines for Bay State. Bay State Gas Company, D.T.E. 99-84, Letter Order (May 28, 2002) ("Letter Order").[233] With respect to staffing levels and training, Bay State's SQ Plan restates the language of the Guidelines: "Staffing benchmarks will be established on a company-specific basis and will be determined by the then effective collective bargaining agreement for each Company." Letter Order at 3-5.

Since Bay State's acquisition by NiSource, the number of Bay State managers and employees has dropped from 811 total employees in 1998 to 586 employees in 2005 (Exh. UWUA 1-1). Further, NiSource recently has entered into an outsourcing agreement with IBM regarding the telephone call answering and customer billing functions, which jobs are currently filled by more than 100 Bay State employees (RR-AG-9 (Confidential)).

B. Positions of the Parties

1. Attorney General

The Attorney General argues that in enacting G.L. c. 164, § 1E(b), the Legislature expressly recognized that utility companies making PBR filings would seek to reduce costs by decreasing staffing levels in such a way that would cause service quality to deteriorate (Attorney General Brief at 121-122). The Attorney General contends that Bay State engaged in extensive outsourcing of employee positions and duties that resulting in a 1998 gas line

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[233] Although Bay State was not operating under a PBR at the time, it had an SQ Index under its acquisition-related rate plan that would be superceded by the outcome of D.T.E. 99-84. Letter Order at 5.

explosion in Attleboro, caused by an error by the Company's outsourced Dig-Safe contractor that resulted in two deaths, seven injuries, and extensive property damage[234] (id. at 122-123, citing Exh. UWUA-4, at 2-3; Tr. 16, at 2654). Thus, the Attorney General argues that further staffing reductions without Department review likely will pose a threat to public safety (Attorney General Brief at 122, citing Exhs. AG-2; UWUA-4, at 28; UWUA-4, at 2-3; Tr. 16, at 2654).

The Attorney General urges the Department to require, at a minimum, Bay State to maintain staffing levels at current 2005 levels, so that the Company's service quality does not decline (Attorney General Brief at 121). The Attorney General also proposes that further reductions in staffing levels should be prohibited unless or until the Company demonstrates to the Department that any staffing reductions or outsourcing are consistent with the respective collective bargaining agreements and will not put service quality and reliability at risk (id. at 121, citing Tr. 16, at 2658-2659). The Attorney General argues that this rate proceeding is the appropriate forum to consider Bay State's staffing levels, because service quality is an integral element in the ratesetting process (Attorney General Reply Brief at 54-56).

2. Local 273

Local 273 asserts that the Company has been "less than fully candid" with the Department in terms of NiSource's plans to outsource key Massachusetts-based functions

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[234] On March 4, 1998, a gas explosion in Attleboro resulted in the deaths of two municipal employees, seven injuries, the destruction of one house, and damage to 68 other homes (Exh. AG-2, at 4). The Department determined that this accident was caused by failure of the Company's then-outsourced Dig-Safe location service to properly designate the location of a gas line (id., at 10).

including Bay State's call center and billing functions (UWUA Brief at 14). Local 273 contends that it is evident that NiSource intends to outsource over 1,000 jobs throughout its system, including more than 100 billing and call center jobs in Massachusetts alone (id.).

Local 273 also argues that Bay State "misled" the Department when it sought approval for its acquisition by NiSource (UWUA Brief at 11). Local 273 contends that representations made by Bay State and NiSource in D.T.E. 98-31 have proved false (id.). Specifically, Local 273 argues that at the time of the evidentiary hearings in D.T.E. 98-31, Massachusetts-based Company executives were either not telling the Department the truth, or that NiSource had been withholding key corporate plans from them, when making the following claims: (1) utility operations would not be adversely affected; (2) Bay State's management and organizational structure would remain intact; and (3) the merger would lead to significantly increased sales (id.). Local 273 maintains that rather than fulfilling its promised obligations, NiSource wrested control of Bay State from its local management and that NiSource officers disregard the interests of Massachusetts ratepayers (UWUA Brief at 36-39, 46-47). Further, Local 273 contends that NiSource has reduced Bay State's personnel, particularly its sales force and management staff (UWUA Brief at 12-14; UWUA Reply Brief at 4). Finally, Local 273 maintains that NiSource has prevented Bay State from expanding its business (Exh. UWUA-4 at 29).

According to Local 273, NiSource's acquisition of Columbia Energy Group increased NiSource's level of long-term debt to a level that contributed to disappointing financial results (UWUA Brief at 36-39). As a result, Local 273 asserts that NiSource disregarded its stated intent in the D.T.E. 98-31, reduced staff, failed to invest in infrastructure, and allowed Bay

State's customer service to deteriorate (Exh. UWUA-4, at 21, 29-30). Therefore, Local 273 recommends that the Department adopt firm, enforceable benchmark staffing levels for Bay State and order a management audit of the Company with respect to three areas: (1) whether the Company has sufficient Massachusetts-based managers to properly manage the Company and deliver high-quality, safe and dependable service, including whether those managers have sufficient ability to obtain from NiSource the staff and capital resources necessary; (2) whether there are adequate staff to answer telephone inquiries, perform all billing-related functions, and inspect, maintain and repair the Company's infrastructure; and (3) whether the extent to which NiSource has outsourced Bay State's employees' job functions has posed a risk of degradation to service quality (UWUA Brief at 60; UWUA Reply Brief at 7-8).

3. Steelworkers

Likewise, the Steelworkers argue that NiSource has wrested control of the Company's staffing decisions from local management and has failed to provide adequate call center staffing levels, resulting in a serious deterioration in service quality (Steelworkers Brief at 3-6). The Steelworkers also assert that, because NiSource had sole control over negotiations with IBM Global on the Outsourcing Agreement, the Company was precluded from offering any input into negotiations that the Steelworkers contend will result in the outsourcing of all call center and billing positions for Bay State (id. at 6-9). The Steelworkers state that given the Company's inability to control staffing levels, the Department should set minimum staffing levels to ensure that customer service does not further deteriorate (id. at 13-15).

4. Company

Bay State argues that is has provided extensive documentation and sworn testimony regarding the Company's forward-looking plans and proposals, including those involving the Outsourcing Agreement (Bay State Brief at 13). Bay State contends that it is always seeking opportunities to concentrate on its core functions of ensuring safe, reliable and cost-efficient service, and recognizes that it is under continuing obligation imposed by the Department to explore all cost-savings measures and potential opportunities to achieve efficiencies of all kinds (id., citing Mergers and Acquisitions and Mergers, D.P.U. 93-167-A at 5 (1994)).

The Company maintains that it engaged in diligent investigation of the various aspects of the Outsourcing Agreement, and believes that the Outsourcing Agreement will ensure the safe and reliable service the Company provides by freeing up capital resources that can be invested in its distribution and pipeline operations (Bay State Brief at 14). Bay State claims that its participation in NiSource's outsourcing initiative with IBM does not mean that the Company employees will lose their jobs, because many employees may become employed by either IBM Global or an IBM Global subcontractor (Bay State Brief at 14, citing Exhs. DTE 18-1; AG 3-8; Tr. 1, at 191; Tr. 16, at 2674).[235]

Bay State acknowledges that although its telephone service quality did deteriorate for a brief period in the past due to inadequate staffing, the Company remedied these problems before the test year (Bay State Brief at 14-15). The Company asserts that although staffing

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[235] The Company has used the term "rebadged" (Bay State Brief at 14 citing Exhs. DTE 18-1; AG 3-8; Tr. 1, at 191; Tr. 16, at 2672-74). We decline to employ that term.

cuts were initiated while introducing new technologies, when SQ deteriorated, the Company took action to address the problem (id. at 15). The Company emphasizes that the Outsourcing Agreement will not relieve the Company of any customer service standards established by the Department, and that the Outsourcing Agreement is intended to produce a higher level of customer service at a lower cost (id.).

The Company concludes that its history demonstrates a consistent, steady management direction towards a stronger, financially stable, highly reliable and efficient gas distribution system (id. at 21). The Company contends that it has met or exceeded its service quality measures for three years leading up to this rate proceeding, and that the evidence further demonstrates greater local control for the Company and an improved record of customer satisfaction (id. at 21, citing Exh. BSG/SHB-1, at 28-30; Tr. 20 at 3304).

The Company disputes Local 273's contention that the Department has been lax in its investigation of Bay State, arguing that the Department's investigation in D.T.E. 99-84, as well as the implementation of the rules established by that proceeding, had been balanced and thorough (id. at 22). The Company argues that if Local 273 believes changes in the Department's service quality measures are warranted, Local 273 should propose such measures as part of the Department's investigation in D.T.E. 04-116 (id.). Concerning Local 273's assertion that the Department has failed to enforce staffing level requirements, the Company contends that this investigation is not the appropriate forum in which findings of statewide impact should be made (i.e., statutory interpretations regarding G.L. c. 164, §§ 1E and 1F are improper in a base rate proceeding) (Bay State Brief at 23). The Company argues that the Department's duty is not to micromanage a utility's staffing levels, and that all utilities should

have the opportunity to comment on an issue of statewide impact, such as service quality measures (id. at 23).

C. Analysis and Findings

A regulated utility must have properly trained staff, available in adequate numbers, to maintain service quality. Customers' rates entitle them to no less. The adequacy of properly trained staff as a contributing element to a company's maintaining quality in its service to ratepayers is a matter of great importance. See, e.g., D.T.E. 03-40, at 506; NSTAR, D.T.E. 01-65, at 16 (2002). Bay State's SQ Plan captures only statutorily specified categories, but not all aspects of Bay State's requirements to meet its public service obligations. D.T.E. 99-84, at 20-21, 43; see also Commonwealth Electric Company, D.P.U. 84-114 (1984). The Company is obligated to serve the public interest by providing reliable, safe service at a reasonable cost. See, e.g., D.P.U. 89-114, at 193; D.P.U. 86-36-C, at 87 (1988). The Department is charged to determine that the Company's management decisions are carried out in a manner consistent with the public interest. See, e.g., D.P.U. 89-114/90-331/91-80 (Phase 1) at 193; see also G.L. c. 164, § 76.

In the current proceeding, the Department has determined that there are several issues that require further investigation concerning NiSource's management control of Bay State and staffing levels for Bay State's operations. In particular, we seek to sharpen our understanding of whether Bay State has engaged in labor displacements that are below statutorily-mandated staffing levels or that otherwise may impede service quality. G.L. c. 164, § 1E.

The record suggests that the motivation of this displacement may stem as much, if not more, from Bay State's parent as from the Company itself. Pursuant to G.L. c. 164, § 76A,

the Department has general supervision over affiliated companies as defined by G.L. c. 164, § 85, with respect to all direct and indirect relations, transactions, and dealings with the gas or electric company with which it is affiliated, which affect the operations of said gas or electric company. The Department has authority pursuant to G.L. c. 164, § 85 to examine the books, contracts, records, documents, and memoranda or physical property of any company subject to this chapter, as well as of any affiliated company with respect to any direct or indirect relations, transactions, or dealings between such affiliated company and any company subject to Department jurisdiction under this chapter. While the Department has authority pursuant to Section 1E to staffing level benchmarks for gas and electric companies, we have not as of yet set such benchmarks for Bay State. The Department has stated previously that staffing levels must be addressed in an appropriate forum where interested parties may participate, and that a rate case is not an appropriate forum. D.T.E. 03-40, at 506 (2003). The instant investigation under G.L. c. 164, § 94, however, sets the stage for a Section 1E enquiry.

As we noted in Section VII.B.5, above, this proceeding has raised questions about NiSource's resource and service decisions and how they may have affected Bay State's ability to serve its ratepayers. We emphasize here that the record in the present docket raises questions not so much about Bay State's local management in Westborough, who strive to maintain service in the face of NiSource's resource allocation decisions, but about NiSource's management decisions from Merrillville, Indiana that affect the Company. Therefore, pursuant to Section 1E(b), the Department's general supervisory authority over Bay State pursuant to G.L. c. 164, § 76, the Department's authority over contracts and the Department's authority over affiliated transactions pursuant to G.L. c. 164, § 85, the Department will open a

new investigation and issue a procedural schedule regarding this matter no later than the end of the first calendar quarter of 2006. We anticipate concluding this proceeding by the end of third quarter of 2006.

This Section 1E proceeding will allow the Department to analyze the specific questions of whether Bay State complies with the statutory mandate set out in Section 1E. The Department will benefit from a full evidentiary record and briefing on Section 1E requirements and the exceptions to it.

The Department will investigate a number of topics concerning NiSource's management control of Bay State and staffing levels for Bay State's operations. While we do not itemize each topic at this time, we list several as a guide to our inquiry for Bay State and NiSource, as well as other interested parties. First, the Department will investigate whether NiSource's control of Bay State's operations has impaired, or enhanced, the delivery of quality, reliable service at least cost to the Companies' ratepayers. Second, the Department will also investigate NiSource's reduction in Bay State's personnel, particularly its sales force, customer service representatives, maintenance staff, and management staff and whether such reductions have impaired, or made more efficient, Bay State's ability to adequately maintain its distribution system.[236] Finally, the Department will also investigate the circumstances, and NiSource's role, if any, in Bay State's low sales growth.

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[236] There is record evidence, discussed in this Order at Section V.D, that the contemplated IBM Global Agreement may result in a management decision to move the functions of a number of Bay State's direct employees to contract status. In light of our pending Section 1E review, such a decision, if contemplated, may be premature.

XI. ANNUAL BASE RATE ADJUSTMENT MECHANISM

A. Company Proposal

Bay State proposes a separate tariff (M.D.T.E. No. 63) for its Annual Base Rate Adjustment Mechanism ("ABRAM") (Exh. BSG/JAF-2, Sch. JAF-2-8, at 2-16). The ABRAM adjusts annually the Company's base distribution rates for PBR, SIR and the impact of energy efficiency savings ("EES") due to therm savings from the Company's demand-side management ("DSM") program (i.e., lost base revenues ("LBR")) (id.). According to Bay State, the annual base rate adjustment formula shall be applied for each base rate element of each rate schedule and shall be calculated in accordance with the following formula:

$$BR^{n,e}_{T} = (BR^{n,e}_{T-1} - BR_SIR^{n,e}_{T-1}) \times (1 + PBR_CAP^{n,e}_{T}) \times (1 + EE_ADJ^{n,e}_{T}) + BR_SIR^{n,e}_{T}$$

where:

$BR^{n,e}_{T}$ = The Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year;

$BR^{n,e}_{T-1}$ = The Base Rate Element *e* applicable to Rate Schedule *n* for the Prior Year*;*

$BR_SIR^{n,e}_{T-1}$ = The SIR Base Rate for Base Rate Element *e* applicable to Rate Schedule n for the Prior Year;

$PBR_CAP^{n,e}_{T}$ = The percentage change for Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year calculated pursuant to the Company's PBR plan*;*

$EE_ADJ^{n,e}_{T}$ = The Energy Efficiency Adjustment Percentage for Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year*; and*

$BR_SIR^{n,e}_{T}$ = The SIR Base Rate Element *e* applicable to Rate Schedule *n* for the Rate Year.

(id.)[237]

The initial base rates will be established in the instant docket, D.T.E. 05-27, and the first ABRAM change to base rates will be effective November 1, 2006 (id.). According to Bay State, incorporating the different components of the Company's rates into a single tariff "increases the ease with which the annual adjustments are filed by the Company, implemented and reviewed by the Department." (Exh. BSG/JAF-2, at 25).

The Company proposes a three-step implementation of the ABRAM (id.). First, the Company will apply the PBR price-cap adjustment to the rate for the prior year exclusive of SIR revenue requirements (id.). Next, the PBR-adjusted base rate will be further adjusted to reflect the impact of EES (id. at 26). Lastly, the result of these adjustments is increased by the amount of the SIR Base Rate (id.). According to Bay State, the Company will base the billing determinants in the base rate adjustment calculations upon the weather-adjusted actual throughput volumes and customer numbers, by rate element, for the previous calendar year, normalized for weather variances that occurred during the calendar year (id. at 27-28). The Company states that the use of weather-adjusted actual throughput volumes in base rate adjustment calculations is consistent with the PBR mechanism that the Department approved for Boston Gas in D.T.E. 03-40, and "serves to derive appropriate rate levels consistent with the development of billing determinants in a general rate case proceeding." (id. at 28).[238]

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237 The Company provided separate formulas for calculating the individual components of the ABRAM in Exhibit BSG/JAF-2, Schedule JAF-2-8, at 6-16.

238 The Company states that the billing determinants established in the instant proceeding will not be relied upon to derive future PBR rate adjustments (Exh. BSG/JAF-2, at 28).

According to Bay State, the incorporation of the proposed energy efficiency adjustment in the ABRAM is necessary because the Company's PBR price-cap formula does not implicitly account for the recovery of LBR associated with the Company's energy efficiency or DSM programs (id. at 30). The Company states that "[f]ailure to adjust for energy efficiency savings in conjunction with an index-based PBR mechanism would perpetuate under-earning by the Company." (id. at 30).[239]

According to Bay State, the Company's proposal to recover LBR through the ABRAM will adjust its most current "test year" ("Prior Year") revenues through a rate adjustment reflecting that year's annual energy efficiency therm savings (Exh. DTE 12-7). Any installed measures not recorded for the Prior Year by the time the Company has filed its annual base rate adjustment (i.e., by June 1 of each year) will not be used to calculate LBR in future years (Exh. DTE 12-6).[240]

Bay State proposes to recover the costs associated with the SIR program less any O&M expense savings through the ABRAM (Exh. BSG/JAF-2, Sch. JAF-2-8, at 11-12). According

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239 Bay State states that absent a provision to adjust for energy efficiency savings through the ABRAM, the Company would need the current LBR recovery mechanism through the LDAC in order to be sufficiently compensated for the lost base revenue as a result of the reduced therm throughput associated with the installation of energy efficiency measures (Exh. DTE 12-6).

240 The Company stated that under the current LBR recovery mechanism through the LDAC, cumulative LBR recovery is limited to the Rolling Period Method ("RPM") average number of years between the Company's last four rate cases (Exh. DTE 12-7). For Bay State, this means that the Company would be eligible to recover LBR associated with all measures installed within the prior four years (Exh. DTE 12-7). According to the Company, if Bay State were to continue to recover LBR using the RPM, at the conclusion of this proceeding, the Company's RPM number of years of installed measures would be seven instead of four (Exh. DTE 12-7).

to the Company, the SIR revenue requirements shall be recovered from customers through each base rate element of the Company's firm rate schedules by applying a SIR Base Rate Adjustment to each existing Base Rate Element excluding the SIR Base Rate for the Prior Year (id. at 15). The SIR Base Rate Adjustments shall be derived by allocating the overall SIR Revenue Requirements to each Base Rate Element by the percentage of Prior Year total base revenues associated with each Base Rate Element (id.). The resulting revenues by each Base Rate Element are then divided by the corresponding weather-normalized billing determinants for the Prior Year to derive the SIR Base Rate Adjustment (id.).

B. ABRAM Compliance Filing

On or before June 1, 2006, and annually thereafter through 2009, Bay State proposes to submit a tariff filing containing proposed revised tariff sheets to implement rate changes with the Department for review and approval of the Company's Energy Efficiency Adjustment and the SIR Revenue Requirements and the SIR Base Rates to be included in the ABRAM for the subsequent Rate Year (id. at 11, 15-16). The compliance filing shall include a description of the energy efficiency measures installed and associated therm savings by Rate Schedule and descriptions of all SIR Investments and the results of the calculation of the SIR Revenue Requirements Formula for the Rate Year (id. at 11, 16). The Company shall also file information on the Company's Annual SIR Budget filed the previous year as well as any material variances in the SIR project costs (id. at 16).

C. Positions of the Parties

1. Attorney General

The Attorney General contends that the Department should reject Bay State's proposal to recover LBR through the ABRAM for the following reasons: (1) the Department's PBR formula is a price-cap formula provides for the adjustment of current rates (prices), and not revenues, based on an adjusted inflation index (Attorney General Brief at 51, n.30, citing, Boston Gas Company, D.T.E. 97-92, at 1 (1997)), and (2) Bay State has entered into a settlement agreement which governs its energy efficiency program and the recovery of costs, including LBR recovery (Attorney General Brief at 50, citing, Bay State Gas Company, D.T.E. 04-39, Settlement Agreement § II., at 10-11 (August 12, 2004)).

2. Company

Bay State disagrees with the Attorney General that because the Company's price-cap formula adjusts for current rates (prices), and not revenues, the Department should reject the Company's proposal to recover LBR through the ABRAM (Bay State Brief at 65-68). According to Bay State, the Department should allow the Company to recover LBR "[p]recisely because the PBR adjusts average prices resulting from revenues generated by billing determinants suppressed or reduced by energy efficiency therm savings" (id. at 65, citing Exh. BSG/JAF-3, at 30-31).

D. Analysis and Findings

1. Energy Efficiency Adjustment

In D.T.E. 97-112, at 32-33, the Department modified its LBR policy for all local gas distribution companies by limiting LBR recovery to a period equal to the average historic time span between the last four rate cases for each company ("Rolling Period Method" or "RPM").[241] The Department has allowed companies that propose LBR recovery to recover them through the LDAC. See, e.g., Colonial Gas Company, D.T.E. 01-73, at 15, 18-20 (2002). In the instant case, the Department notes that Bay State's proposal to recover LBR through the ABRAM, rather than through a separate recovery mechanism that is a component of the LDAC, is problematic.

If approved, the proposal would change the terms of the Settlement in Bay State Gas Company, D.T.E. 04-39 between the Company and the parties to the Settlement ("Parties")[242] which stipulated the RPM method for calculating energy efficiency savings and the LDAC as the appropriate recovery mechanism. The Parties have neither commented on nor approved the Company's proposal to modify the terms of the Settlement (Tr. 19, at 3025-3027; RR-DTE-125;). Second, the current method for LBR recovery is the result of a generic investigation and applies to all LDCs in Massachusetts. Modifications to the LBR recovery mechanism should not be accomplished without appropriate notification to all interested

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241 Previously, LBR for DSM programs installed since a company's last rate case were recoverable over the lives of the programs installed. D.T.E. 97-112, at 9-11.

242 The parties to the Settlement include Bay State, DOER, the Low Income Energy Affordability Network ("LEAN"), and the Department. D.T.E. 04-39, Settlement Agreement at 1 (August 12, 2004).

parties. Third, the proposal, if approved, will leave the Department with little time (i.e., 1.5 months) to review the Company's LBR filings, which, historically, have involved pre-filed testimonies, rounds of discovery, and evidentiary hearings. Finally, the Company's proposal to estimate energy efficiency savings on an annual basis is not consistent with the RPM[243] approved by the Department in D.T.E. 97-112. For these reasons, the Department rejects the Company's proposal to recover the LBR associated with its DSM programs through the ABRAM.

2. SIR Base Rate Adjustment

The Department has found in Section II that the Company's proposed SIR base rate adjustment mechanism is not necessary. Accordingly, the Department rejects the SIR base rate adjustment mechanism as a component of the ABRAM.

Because the Department has rejected the proposed energy efficiency adjustment and the SIR base rate adjustment, the remaining portion of the ABRAM will only be the PBR base rate adjustment. However, the Department has directed the Company to make its annual PBR compliance filing in the Section IX of this Order. Therefore, the Department finds that the proposed ABRAM tariff, M.D.T.E. No. 63, is no longer necessary and, accordingly, is rejected.

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[243] In D.T.E. 97-112, the Department modified its LBR policy for all gas distribution companies by limiting LBR recovery to a period equal to the average historic time span between the last four rate cases for each company of the RPM (D.T.E. 97-112, at 32-33). For Bay State, the average historic time span between the Company's last four rate cases is four years. This means that Bay State can only recover LBR for DSM measures installed in the last four years.

XII. COMPANY'S REQUEST FOR POST-ORDER BILLING AUTHORITY

A. Introduction

On November 21, 2005, Bay State filed with the Department a Motion for Certain Post-Order Billing Authority ("Post-Order Motion"). By its Post-Order Motion, the Company requests that the Department grant Bay State certain billing authority for the period from the date of issuance of this Order (November 30, 2005) until the Department approves the Company's filing to be made in compliance with the directives of this Order ("compliance filing") (Post-Order Motion at 1). Specifically, Bay State requests that it be permitted to continue to bill its customers according to the schedule of their regular billing cycles for consumption on after December 1, 2005, at "temporary base rates equivalent to the base rates in effect prior to the date of" this Order (id.). Bay State requests that these "temporary base rates" remain in effect until the Department has reviewed and approved the Company's compliance filing (id.). Bay State proposes that for those customers billed at the temporary rates, the Company would make an adjustment on each customer's bill for the difference in the temporary rates and the new rates determined through the compliance filing, without interest (id. at 1-2). This billing adjustment would be based on each customer's level of consumption billed at the temporary rates (id.).[244]

In accordance with the schedule established by the Hearing Officer, the Attorney General filed a reply on November 23, 2005, opposing the Post-Order Motion ("Attorney General Reply").

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[244] Bay State proposed a bill message to explain to customers the application of the temporary rates and the subsequent billing adjustment.

B. Company's Position

Bay State notes that when the Department issues an order in a base rate proceeding for a gas or electric company, the order typically provides that the new rates shall apply to gas or electricity consumed on or after the day following the date of the order, and that, unless otherwise ordered by the Department, the new rates will not become effective earlier than seven (7) days after the company has made its compliance filing (Post-Order Motion at 2). Bay State contends that the process of the Company's making its compliance filing and the Department's approving it could take two weeks or longer (id.). Bay State maintains that during this period, it often is the practice of the utility to interrupt the standard customer billing cycle and hold the bills until the new rates are finally determined (id.).

Bay State asserts that its customers have come to rely of the timing of the receipt of their natural gas bills, in order to monitor their energy consumption and monthly expenses (id.). Bay State contends that bills rendered to the Company's customers in December 2005 and January 2006 will be significantly larger than their recent bills and bills rendered last year for the same period, resulting from the high commodity costs for winter 2005-2006 consumption (id. at 2-3).

The Company states that if it holds customers' bills until Bay State's compliance filing is approved, a large segment of its customers, those who normally receive bills in early to mid December, will not receive their bills until the middle of December or later (id.). The Company further states that these customers will receive another bill shortly thereafter as the billing cycles for January 2006 begin (id.). The Company contends that because the December and January bills will include winter heating gas consumption at winter base rates and winter

cost of gas rates, customer will receive back-to-back high gas bills, only a few weeks apart (id.). Bay State argues that this timing will confuse customers (who will not understand why the Company must hold bills) and likely cause financial hardship and other difficulties for customers (id.).

Bay State contends that its proposal would not violate the general prohibition against retroactive ratemaking, because that prohibition applies only to rates that have been fixed as final by the Department (id. at 4, n.1).[245] Bay State asserts that the prohibition does not apply when rates have been approved on a temporary basis, and customers have been put on notice that such rates are temporary and will be subject to future adjustment (id., citing Boston Gas Company, D.T.E. 96-50-D at 8-10 (2001); Boston Edison Company, D.T.E. 04-113-A (2005)).

C. Attorney General

The Attorney General asserts that the Department's traditional practice is to require a company to hold bills pending the Department's approval of the compliance filing (Attorney General Reply at 1). The Attorney General argues that the Company has provided no convincing argument for a departure from this precedent (id.). The Attorney General further argues that the creation of the Company's new reconciling rate structure would require notice and a hearing under G.L. c. 164, § 94 to determine the propriety of the rates before approval (id., citing Consumers Organization For Fair Energy Equity, Inc. v. Department of Public

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[245] A rate increase may not be awarded retroactively as a matter of law. Boston Edison Company v. Department of Public Utilities, 375 Mass. at 6.

Utilities, 368 Mass. 599, 606 (1975)). The Attorney General concludes that the Department should deny the Company's request.

D. Analysis and Findings

On April 27, 2005, Bay State filed new proposed tariffs to take effect June 1, 2005. On April 28, 2005, the Department suspended the operation of those tariffs until December 1, 2005, pending its investigation in this docket into the propriety of those tariffs. During the pendency of this investigation, Bay State's presently filed tariffs remained in effect.

By the Order issued today, the Department has denied Bay State's tariffs filed on April 27, 2005, and issued directives to the Company for the new rates to take effect December 1, 2005. Those new rates will be subject to approval by the Department after the Company makes its detailed compliance filing implementing our Order. As the Company has noted, in order to bill customers under the new rates, the Company will need to interrupt its billing until the Department approves the compliance filing.

General Laws chapter 164, section 94 ("Section 94") provides that gas and electric companies must file with the Department the schedules (tariffs) showing all rates, prices and charges to be charged or collected for the sale and distribution of gas or electricity. Section 94 further provides that gas and electric companies may file new tariffs with changed rates, prices and charges, but until the effective date of such changes "no different rate, price or charge shall be charged, received or collected by the company filing such a schedule from those specified in the schedule then in effect".

Thus, Section 94 requires that gas and electric companies may only charge the rates as provided in their tariffs on file with the Department and in effect.[246] In the instant case, the rates in effect beginning December 1, 2005 are the just and reasonable rates prescribed by this Order. For gas consumed on and after December 1, 2005, Bay State may not charge any rates other than the rates approved under this Order. Although those rates will not be finally determined until the Department has approved a compliance filing by the Company, under Section 94, Bay State may charge only those rates. Section 94 does not permit the use of the temporary rates sought by Bay State. The rates in effect on November 30, 2005, which had been set in 1997 in D.P.U. 97-97, were terminated by today's Order: those rates have been replaced and, as a matter of law, may no longer be charged.

Therefore, for the reasons stated above, Bay State's Motion for Certain Post-Order Billing Authority is denied. Furthermore, in order to inform customers of the Company's billing conditions as a result of the compliance filing requirements, the Company shall include a bill message with its December bills explaining the timing of bills in December 2005 and January 2006 affecting customers in the billing cycles that were interrupted. The Company shall provide the Department with a draft of that bill message.

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[246] These requirements of Section 94 embody the principles of the "filed rate doctrine." The general requirement of the filed rate doctrine is that public utilities and common carriers file tariffs with regulatory agencies and provide service pursuant to those tariffs. In a 1915 case, the United States Supreme Court explained the operation of the filed rate doctrine as follows: "The rate of the carrier duly filed is the only lawful charge. Deviation from it is not permitted upon any context." Louisville & Nashville Rail Company v. Maxwell, 237 U.S. 94, 97 (1915). The case citations in the Post-Order Motion at 4, n.1, are inapposite. One, in fact, concerns a reconciling mechanism, rather than tariffed base rates. Boston Edison Company, D.T.E. 04-113-A (2005).

SCHEDULE 1

REVENUE REQUIREMENTS AND CALCULATION OF REVENUE INCREASE

	PER COMPANY	COMPANY ADJUSTMENT	DTE ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	407,006,651	(78,812)	(1,865,809)	405,062,030
Depreciation	28,800,958	10,148	(6,704)	28,804,402
Amortization	6,552,895	79,161	(2,355,433)	4,276,623
Taxes Other Than Income Taxes	10,067,165	(110,345)	0	9,956,820
Income Taxes	16,082,994	(287)	(2,083,625)	13,999,082
Interest on Customer Deposits	72,506	0	0	72,506
Amortization of ITC	(373,740)	0	149,811	(223,929)
Return on Rate Base	35,938,150	(119,781)	(3,483,372)	32,334,997
Total Cost of Service	504,147,579	(219,916)	(9,645,131)	494,282,531
OPERATING REVENUES				
Operating Revenues	510,457,335	0	0	510,457,335
Revenue Adjustments*	(28,129,335)	352,622	455,911	(27,320,802)
Total Operating Revenues	482,328,000	352,622	455,911	483,136,533
Total Base Revenue Deficiency	**21,819,579**	**(572,538)**	**(10,101,042)**	**11,145,998**

* The Per Company column includes $418,748 in special contract revenues omitted from the Company's filed schedules, but included in the Company's Cost of Service. See Schedule 9 for details.

SCHEDULE 2

OPERATIONS AND MAINTENANCE EXPENSES

	PER COMPANY	COMPANY ADJUSTMENT	DTE ADJUSTMENT	PER ORDER
Purchased Gas Expense	323,863,512	0	0	323,863,512
Total Adj. to Purchased Gas Expense	(16,384,861)	0	0	(16,384,861)
Total Purchased Gas Expense	307,478,651	0	0	307,478,651
O&M Expense	99,007,484	0	0	99,007,484
ADJUSTMENTS TO O&M EXPENSE:				
Payroll - Union	1,173,418	52,656	0	1,226,074
Payroll - Non Union	443,840	10,473	0	454,313
Incentive Compensation	(124,422)	0	0	(124,422)
Benefits:				
Medical Insurance	684,618	0	0	684,618
Dental Insurance	56,427	0	0	56,427
Property & Liability Insurance	94,997	(170,113)	(136,754)	(211,870)
Self Insurance Claims	80,021	62,945	(295,741)	(152,775)
Bad Debt Expense - Gas Revenue	7,106,032	(86,279)	0	7,019,753
Bad Debt Related to Requested Revenue Increase	482,572	(16,599)	(226,334)	239,639
Bad Debt Expense - EP&S	246,232	0	36,059	282,291
NiSource Corporate Jet	0	0	(728)	(728)
Westborough Lease	0	0	(756,009)	(756,009)
CGA Bad Debt Tracker	(5,290,135)	0	0	(5,290,135)
LDAC Trackers	(3,937,032)	0	0	(3,937,032)
NiSource Corporate Services Company	748,123	(36,084)	0	712,039
Rents and Leases	(2,608,947)	(22,085)	0	(2,631,032)
Materials and Supplies	67,947	0	0	67,947
Advertising	0	0	(350,285)	(350,285)
Other O&M Expenses	162,729	(310,000)	0	(147,271)
Farm Discounts	15,320	0	(7,660)	7,660
Gain on Sale of Property	(408,197)	0	204,099	(204,098)
Rate Case Expense	331,700	158,345	(248,571)	241,474
Inflation	1,195,274	277,929	(83,886)	1,389,317
Sum of O&M Expense Adjustments	520,516	(78,812)	(1,865,809)	(1,424,105)
Total O&M Expense	**99,528,000**	**(78,812)**	**(1,865,809)**	**97,583,379**

SCHEDULE 3

DEPRECIATION AND AMORTIZATION EXPENSES

	PER COMPANY	COMPANY ADJUSTMENT	DTE ADJUSTMENT	PER ORDER
Depreciation Expense	28,800,958	10,148	(6,704)	28,804,402
Amortization Expense	6,552,895	79,161	(2,355,433)	4,276,623
Total Depreciation & Amortization Expenses	**35,353,853**	**89,309**	**(2,362,137)**	**33,081,025**

SCHEDULE 4

RATE BASE AND RETURN ON RATE BASE

	PER COMPANY	COMPANY ADJUSTMENT	DTE ADJUSTMENT	PER ORDER
Utility Plant in Service	760,883,211	0	(10,430,541)	750,452,670
LESS:				
Reserve for Depreciation and amortlization	264,064,800	0	(4,722,741)	259,342,059
Net Utility Plant in Service	496,818,411	0	(5,707,800)	491,110,611
ADDITIONS TO PLANT:				
Cash Working Capital	11,453,613	(7,194)	(135,704)	11,310,715
Materials and Supplies	3,408,069	0	0	3,408,069
Total Additions to Plant	14,861,682	(7,194)	(135,704)	14,718,784
DEDUCTIONS FROM PLANT:				
Work in Progress	6,332,113	0	106,205	6,438,318
Reserve for Deferred Income Tax	85,522,538	0	(2,220,073)	83,302,465
Amortization of Intangible Plant	19,327,463	0	0	19,327,463
Unamortized ITC-Pre1971	11,170	0	0	11,170
Customer Contribution	3,090,784	0	0	3,090,784
Customer Advances	11,088	0	0	11,088
Unclaimed Funds	278,310	0	0	278,310
Total Deductions from Plant	114,573,466	0	(2,113,868)	112,459,598
RATE BASE	397,106,627	(7,194)	(3,729,636)	393,369,797
COST OF CAPITAL	9.05%	-0.03%	-0.80%	8.22%
RETURN ON RATE BASE	**35,938,150**	**(119,781)**	**(3,483,372)**	**32,334,997**

SCHEDULE 5
COST OF CAPITAL

	PER COMPANY			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$183,500,000	46.05%	6.18%	2.85%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$214,940,703	53.95%	11.50%	6.20%
Total Capital	$398,440,703	100.00%		9.05%
Weighted Cost of				
Debt				2.85%
Equity				6.20%
Cost of Capital				9.05%

	PER COMPANY - ADJUSTED			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$183,500,000	46.05%	6.12%	2.82%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$214,940,703	53.95%	11.50%	6.20%
Total Capital	$398,440,703	100.00%		9.02%
Weighted Cost of				
Debt				2.82%
Equity				6.20%
Cost of Capital				9.02%

	PER ORDER			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$183,500,000	46.05%	6.12%	2.82%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$214,940,703	53.95%	10.00%	5.40%
Total Capital	$398,440,703	100.00%		8.22%
Weighted Cost of				
Debt				2.82%
Equity				5.40%
Cost of Capital				**8.22%**

SCHEDULE 6
CASH WORKING CAPITAL

	PER COMPANY	COMPANY ADJUSTMENT	DTE ADJUSTMENT	PER ORDER
Other O&M Expense	99,045,429	(62,213)	(1,173,503)	97,809,713
Cash Working Capital Allowance *	11,453,613	(7,194)	(135,704)	11,310,715
Total Cash Working Capital Allowance	**11,453,613**	**(7,194)**	**(135,704)**	**11,310,715**
*Composite Total Times (42.21 / 365)	11.564%			

Company O&M expense did not include bad debt related to revenue increase; DTE adjustment includes Department adjustments as well as Company bad debt related to revenue increase.

SCHEDULE 7

TAXES OTHER THAN INCOME TAXES

	PER COMPANY	COMPANY ADJUSTMENT	DTE ADJUSTMENT	PER ORDER
FICA Taxes	2,085,843	3,558	0	2,089,401
Federal Unemployment Taxes	26,314	0	0	26,314
State Unemployment Taxes	460,779	0	0	460,779
Excise Tax	16,856	0	0	16,856
Property Taxes	7,382,453	(113,903)	0	7,268,550
State Franchise	45,845	0	0	45,845
Other State	12,791	0	0	12,791
Other Federal	36,284	0	0	36,284
Total Taxes Other Than Income	**10,067,165**	**(110,345)**	**0**	**9,956,820**

SCHEDULE 8
INCOME TAXES

	PER COMPANY	COMPANY ADJUSTMENT	DTE ADJUSTMENT	PER ORDER
Rate Base	397,106,627	(7,194)	(3,729,636)	393,369,797
Return on Rate Base	35,938,150	(119,782)	(3,483,372)	32,334,996
LESS:				
Interest Expense	11,317,539	(119,335)	(105,176)	11,093,028
Amortization of Investment Tax Credit	373,740	0	(149,811)	223,929
Amortization of Excess Deferred Incomes Taxes	(263,604)	0	0	(263,604)
Total Deductions	11,427,675	(119,335)	(254,987)	11,053,353
Taxable Income Base	24,510,475	(447)	(3,228,385)	21,281,643
Taxable Income	40,329,866	(735)	(5,311,983)	35,017,148
Mass Franchise Tax 6.50%	2,621,441	(47)	(345,278)	2,276,116
Federal Taxable Income	37,708,425	(688)	(4,966,705)	32,741,032
Federal Income Tax Calculated	13,197,949	(240)	(1,738,346)	11,459,363
Total Income Taxes Calculated	15,819,390	(287)	(2,083,625)	13,735,478
Amortization of Investment Tax Credit	(373,740)	0	149,811	(223,929)
Amortization of Excess Deferred Incomes Taxes	263,604	0	0	263,604
Total Income Taxes	**15,709,254**	**(287)**	**(1,933,814)**	**13,775,153**

SCHEDULE 9
REVENUES

	PER COMPANY	COMPANY ADJUSTMENT	DTE ADJUSTMENT	PER ORDER
OPERATING REVENUES PER BOOKS	510,457,335	0	0	510,457,335
Revenue Adjustments				
Weather Normalization	(2,555,582)	0	0	(2,555,582)
Annualized Revenue Adjustment	(15,224,173)	0	0	(15,224,173)
Annualized Indirect GAF and LDAF Revenues	3,336,453	0	0	3,336,453
Off System Sales	(3,874,467)	0	0	(3,874,467)
Lost Net Revenue	(329,961)	0	0	(329,961)
Carrying Costs - Pre Tax of Rate of Return	988,820	0	0	988,820
Production & Storage Revenues	8,085,135	0	0	8,085,135
Energy Products and Services	0	0	794,259	794,259
Special Contracts*	418,748	412,215	(338,348)	492,615
Elimination of Indirect GAF and LDAF	(26,092,473)	0	0	(26,092,473)
Add Back Bad Debt Exp. Included in Indirect Gas Cost	7,118,165	(59,593)	0	7,058,572
Total Revenue Adjustments	(28,129,335)	352,622	455,911	(27,320,802)
Adjusted Total Operating Revenues	**482,328,000**	**352,622**	**455,911**	**483,136,533**

	Operating Revenues removed for Non-distribution services			
Special Contracts*	3,921,013	412,215	(338,348)	3,994,880
Energy Products and Services	14,515,390	0	794,259	15,309,649
Reactivation Fee	34,855	0	0	34,855
Warrant Fee	7,270	0	0	7,270
Locksmith Fee	4,400	0	0	4,400
Late-payment Fee	215,537	0	0	215,537
Returned Check Fee	27,736	0	0	27,736
Gas Property	16,890	0	0	16,890
IC Rental	871,002	0	0	871,002
LNG Tank	178,750	0	0	178,750
Shut-Offs	93,975	0	0	93,975
Pension and PBOP	5,630,282	0	0	5,630,282
Total	**25,517,100**	**412,215**	**455,911**	**26,385,226**

* Although the Company did not include this line in its filed schedules, it appears in the Company's cost of service schedules; additionally, on Brief the Company included an adjustment of $7,363 to special contract revenues that it did not include on its revised schedules. The Department has included this in the Company Adjustment column.

SCHEDULE 10

REVENUE REQUIREMENTS AND CALCULATION OF REVENUE INCREASE BY SERVICE

	TOTAL COMPANY per Order	DISTRIBUTION SERVICE*	GAS SERVICE*	TOTAL COMPANY as filed	DISTRIBUTION SERVICE per Company	GAS SERVICE per Company
Cost of Gas	307,478,651	0	307,478,651	307,478,651	0	307,478,651
O&M Expense	97,583,379	84,609,378	12,974,004	99,528,000	86,295,456	13,232,547
Operations Expenses	405,062,030	85,883,148	319,178,884	407,006,651	86,295,456	320,711,198
Depreciation Expense	28,804,402	28,163,223	641,179	28,800,958	28,159,855	641,102
Amortization Expense	4,276,623	4,179,307	97,316	6,552,895	6,403,782	149,113
Taxes Other Than Income Taxes	9,956,820	9,668,334	288,488	10,067,165	9,775,482	291,685
Income Taxes	13,999,082	13,625,136	373,944	16,082,994	15,653,383	429,609
Interest on Customer Deposits	72,506	72,506	0	72,506	72,506	0
Amortization of ITC	(223,929)	(223,929)	0	(373,740)	(373,740)	0
Rate Base	393,369,797	382,620,602	10,749,197	397,106,628	386,255,320	10,851,309
Rate of Return	8.22%	8.22%	8.22%	9.05%	9.05%	9.05%
Return on Rate Base	32,334,997	31,451,413	883,584	35,938,150	34,956,106	982,043
Cost of Service	494,282,531	177,402,181	316,880,352	504,147,579	180,942,830	323,204,751
Revenues Credited to Cost of Service	(26,385,226)	(26,385,226)	0	(25,517,100)	(25,517,100)	0
Total Cost of Service	**467,897,305**	**151,940,345**	**315,956,962**	**478,630,479**	**155,425,730**	**323,204,751**
Operating Revenues - per books	510,457,335	166,710,611	343,746,724	510,457,335	166,710,611	343,746,724
Revenues Transferred to Cost of Service	(26,385,226)	(26,385,226)	0	(25,517,100)	(25,517,100)	0
Revenue Adjustments	(27,320,802)	(8,766,034)	(18,554,768)	(28,129,335)	(9,025,456)	(19,103,879)
Total Operating Revenues	**456,751,307**	**132,150,813**	**324,600,494**	**456,810,900**	**132,168,055**	**324,642,845**
Revenue Deficiency	**11,145,998**	**11,880,615**	**(734,615)**	**21,819,579**	**23,257,675**	**(1,438,094)**

* The Department has estimated the values in these columns using the ratios derived from the "Distribution Service per Company" and "Gas Service per Company" columns to the "Total Company as filed" column. The actual values for these columns will be known when the Company re-runs its Cost of Service Study.

THIS SCHEDULE IS FOR ILLUSTRATIVE PURPOSES ONLY

SCHEDULE 11 (CORRECTED)

PER ORDER BASE REVENUE INCREASE $11,880,615

RATE CLASS	TEST YEAR BASE REVENUES (A)	ADJUSTED TEST YEAR REVENUES (B)	PER ORDER ADJUSTED TEST YEAR REVENUES (C)	PROPOSED TARGET REVENUE AT EROR (D)	PROPOSED TARGET REVENUE INCREASE AT EROR (E)	PER ORDER TARGET REVENUE INCREASE AT EROR (F)	PER ORDER % INCREASE AT EROR (G)	REVENUE INCREASE AT 125% CAP (H)	REVENUE TARGET AFTER FIRST REVENUE REALLOCATION (I)	REVENUE TARGET AFTER SECOND REVENUE REALLOCATION (J)	PER ORDER TARGET BASE REVENUE REQUIREMENT (K)	PER ORDER (%) BASE REVENUE INCREASE (L)
RESIDENTIAL												
NONHEAT (R-1 & R-2)	$5,318,457	$10,856,303	$5,099,429	$10,473,757	$5,374,328	$2,745,345	53.84%	$572,986	$572,986	$572,986	$5,672,415	11.24%
HEAT (R-3 & R-4)	$88,615,366	$100,492,047	$84,965,957	$96,950,986	$11,985,029	$6,122,262	7.21%	$9,547,009	$7,648,480	$7,659,521	$92,625,478	9.01%
COMMERCIAL (LLF)												
G/T-40	$9,699,385	$11,303,039	$9,299,940	$10,904,751	$1,604,812	$819,779	8.81%	$1,044,967	$991,444	$992,685	$10,292,625	10.67%
G/T-41	$11,649,124	$12,855,832	$11,169,383	$12,402,828	$1,233,445	$630,076	5.64%	$1,255,023	$825,323	$826,735	$11,996,119	7.40%
G/T-42	$6,990,909	$8,252,580	$6,703,006	$7,961,782	$1,258,776	$643,015	9.59%	$753,168	$768,351	$753,168	$7,456,174	11.24%
G/T-43	$1,140,743	$1,455,970	$1,093,764	$1,404,665	$310,901	$158,816	14.52%	$122,898	$122,898	$122,898	$1,216,663	11.24%
COMMERCIAL (HLF)												
G/T-50	$1,909,397	$2,347,139	$1,830,763	$2,264,432	$433,670	$221,530	12.10%	$205,710	$205,710	$205,710	$2,036,472	11.24%
G/T-51	$3,645,186	$4,199,180	$3,495,068	$4,051,213	$556,145	$284,093	8.13%	$392,716	$347,868	$348,329	$3,843,398	9.97%
G/T-52	$3,306,391	$3,549,167	$3,170,226	$3,424,104	$253,878	$129,688	4.09%	$356,215	$183,590	$183,980	$3,354,206	5.80%
G/T-53	$5,569,437	$5,790,935	$5,340,073	$5,586,879	$246,805	$126,075	2.36%	$600,025	$214,024	$214,660	$5,554,734	4.02%
GAS STREET LIGHTS (L)	$478	$345	$458	$333	-$126	-$64	-14.03%	$52	-$59	-$59	$399	-12.88%
TOTAL	$137,844,875	$161,102,537	$132,168,068	$155,425,730	$23,257,662	$11,880,615	8.99%	$14,850,769	$11,880,615	$11,880,615	$144,048,683	8.99%

Note: Schedule 11 is for illustrative purposes only.

(A) Exh. BSG/JAF-2, Sch. JAF 2-1, at 5-6, Line 113.
(B) Exh. BSG/JAF-2, Sch. JAF 2-1, at 5-6, Line 140.
(D) Exh. BSG/JAF-2, Sch. JAF 2-1, at 7-8, Line 213.

161,102,537	137,844,875
46,525	46,525
5,630,282	5,630,282
155,425,730	132,168,068

8.99%	11.24%

XIV. ORDER

Accordingly, after due notice, hearing and consideration, it is

ORDERED: That the tariffs M.D.T.E. 34 through M.D.T.E. 68, filed by Bay State Gas Company on April 27, 2005, to become effective June 1, 2005, are DISALLOWED; and it is

FURTHER ORDERED: That Bay State Gas Company file new schedules of rates and charges designed to increase base revenues by $11,145,998, and it is

FURTHER ORDERED: That Bay State Gas Company shall file all rates and charges required by this Order and shall design all rates in compliance with this Order; and it is

FURTHER ORDERED: That Bay State Gas Company shall comply with all other orders and directives contained herein; and it is

FURTHER ORDERED: That the new rates shall apply to gas consumed on December 1, 2005, but unless otherwise ordered by the Department, shall not become effective earlier than seven (7) days after they are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

/s/

Paul G. Afonso, Chairman

/s/

James Connelly, Commissioner

/s/

W. Robert Keating, Commissioner

/s/

Judith F. Judson, Commissioner

/s/

Brian Paul Golden, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 5, 25.